# Exhibit 1

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the Fiscal Year Ended December 31, 2012**
**Or**
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from _________ to ___________**

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |


77 Beale Street, P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 267-7000
(Registrant's telephone number, including area code)

77 Beale Street, P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)


**Securities registered pursuant to Section 12(b) of the Act:**

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| **PG&E Corporation** : Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company** : First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE Amex Equities |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | | |
|---|---|---|
| PG&E Corporation | Yes ☑ | No ☐ |
| Pacific Gas and Electric Company | Yes ☑ | No ☐ |

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2012, the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $19,276 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |

**Common Stock outstanding as of February 11, 2013:**

| | |
|---|---|
| PG&E Corporation: | 431,436,673 |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

| | |
|---|---|
| Designated portions of the combined 2012 Annual Report to Shareholders | Part I (Items 1, 1A and 3), Part II (Items 5, 6, 7, 7A, 8 and 9A) |
| Designated portions of the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |

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## UNITS OF MEASUREMENT

| | | |
|---|---|---|
| 1 Kilowatt (kW) | = | One thousand watts |
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt (GW) | = | One million kilowatts |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |
| 1 Bcf | = | One billion cubic feet |
| 1 MDth | = | One thousand decatherms |

**Item 1.** ***Business***

**General**

***Corporate Structure and Business***

PG&E Corporation, incorporated in California in 1995, is a holding company that conducts its business through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997.

The Utility's revenues are generated mainly through the sale and delivery of electricity and natural gas to customers. The Utility served approximately 5.2 million electricity distribution customers and approximately 4.4 million natural gas distribution customers at December 31, 2012. The Utility had approximately $52 billion in assets at December 31, 2012 and generated revenues of approximately $15 billion in 2012. The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

***Corporate and Other Information***

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 267-7000 and the Utility's telephone number is (415) 973-7000. PG&E Corporation and the Utility file or furnish various reports with the Securities and Exchange Commission ("SEC"). These reports, including Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended ("1934 Act"), are available free of charge on both PG&E Corporation's website, *www.pgecorp.com* , and the Utility's website, *www.pge.com* , as promptly as practicable after they are filed with, or furnished to, the SEC. The information contained on these websites is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report.

This is a combined Annual Report on Form 10-K of PG&E Corporation and the Utility and includes information incorporated by reference from the joint Annual Report to Shareholders for the year ended December 31, 2012, which is attached to this report as Exhibit 13 ("2012 Annual Report") and the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders. The 2012 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the information in the 2012 Annual Report under the headings "Cautionary Language Regarding Forward-Looking Statements" and "Risk Factors" which appear under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" ("MD&A").

***Operational Improvements***

The Utility's electricity and natural gas businesses are each led by a senior executive who reports to the President of the Utility. During 2012, the Utility continued to build these organizations by adding new leaders with extensive industry expertise and expanding the Utility's work force where needed to implement the Utility's enhanced focus on safety and operational excellence. Significant improvements were made to the Utility's natural gas operations during 2012 to enhance safety, test and replace pipelines, modernize and upgrade the system, and search and validate records. Much of this work was carried out under the Utility's pipeline safety enhancement plan that was approved by the CPUC in late December 2012. The Utility also continued work to implement the safety recommendations made by the National Transportation Safety Board ("NTSB") in its 2011 investigative report on the rupture of one of the Utility's natural gas transmission pipelines in San Bruno, California on September 9, 2010 (the "San Bruno accident"). (For more information, see "Natural Gas Utility Operations" below.) The Utility also undertook significant projects in 2012 to improve and modernize its electricity operations by repairing, replacing or upgrading equipment to improve reliability and safety. In addition, the Utility continued the installation of advanced electric and gas meters throughout its service territory and took other steps to lay the foundation for the development of a "smart grid" to enable customers to have better control over their energy usage and costs, to integrate new

sources of energy (such as distributed generation and storage, rooftop solar and other intermittent energy sources), and to enable the continued safe and reliable operation of the grid. (For more information, see “Electric Utility Operations” below.)

***Employees***

At December 31, 2012, PG&E Corporation and its subsidiaries had 20,593 regular employees, including 20,583 regular employees of the Utility. Of the Utility’s regular employees, 12,492 are covered by collective bargaining agreements with three labor unions: the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO (“IBEW”); the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC (“ESC”); and the Service Employees International Union, Local 24/7 (“SEIU”). There are two collective bargaining agreements with IBEW. One IBEW collective bargaining agreement expires on December 31, 2014 and the other IBEW collective bargaining agreement expires on December 31, 2015. The ESC collective bargaining agreement expires on December 31, 2014. The SEIU collective bargaining agreement expires on July 31, 2013.

## Regulatory Environment

Various aspects of the Utility's business are subject to a complex set of energy, environmental and other laws, regulations, and regulatory proceedings at the federal, state, and local levels. This section and the “Ratemaking Mechanisms” section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. These summaries are not an exhaustive description of all the laws, regulations, and regulatory proceedings that affect the Utility. The energy laws, regulations, and regulatory proceedings may change or be implemented or applied in a way that PG&E Corporation and the Utility do not currently anticipate.

PG&E Corporation is a public utility holding company that is subject to the requirements of the Public Utility Holding Company Act of 2005 (“PUHCA”). Under the PUHCA, public utility holding companies fall principally under the regulatory oversight of the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the PUHCA other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes. These books and records provisions are largely duplicative of other provisions under the Federal Power Act of 1935 and state law.

For discussion of specific pending regulatory proceedings and investigations that are expected to affect the Utility, see the information under the headings within MD&A entitled “Regulatory Matters” and “Natural Gas Matters” in the 2012 Annual Report, which information is incorporated herein by reference.

***Federal Regulation***

*The Federal Energy Regulatory Commission*

The FERC regulates the transmission of electricity and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. The FERC also regulates interconnections of transmission systems with other electric systems and generation facilities, tariffs and conditions of service of regional transmission organizations, including the California Independent System Operator Corporation (“CAISO”), and the terms and rates of wholesale electricity sales. The FERC has authority to impose penalties of up to $1 million per day for violation of certain federal statutes, including the Federal Power Act of 1935 and the Natural Gas Act of 1938, and for violations of FERC-approved regulations. The FERC has jurisdiction over the Utility's electricity transmission annual amount of revenue (“revenue requirements”) and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas.

The FERC has the responsibility to approve and enforce mandatory standards governing the reliability of the nation’s electricity transmission grid, including standards to protect the nation’s bulk power system against potential disruptions from cyber and physical security breaches, to prevent market manipulation, and to supplement state transmission siting efforts in certain electric transmission corridors that are determined to be of national interest. The FERC certified the North American Electric Reliability Corporation (“NERC”) as the nation’s Electric Reliability Organization. The NERC is responsible for developing and enforcing electric reliability standards, subject to FERC approval. The FERC also has approved a delegation agreement under which the NERC has delegated enforcement authority for the geographic area known as the Western Interconnection to the Western Electricity Coordinating Council (“WECC”). The Utility must self-certify compliance to the WECC on an annual basis and the compliance program encourages self-reporting of violations. WECC staff, with participation by the NERC and the FERC, also performs a compliance audit of the Utility every three years. In addition, the WECC and the NERC may perform

spot checks or other interim audits, reports, or investigations. The FERC also has authorized the WECC and the NERC to impose penalties up to $1 million per day, per violation.

The FERC also has adopted policies and rules to promote investment in energy infrastructure and lower costs for consumers through incentive ratemaking for transmission projects. In addition, the FERC's Order No. 1000 establishes electric transmission planning and cost allocation requirements for public utility transmission providers. Order No. 1000 requires public utility transmission providers to improve transmission planning processes and allocate costs for new transmission facilities to the beneficiaries of those facilities.

The CAISO is responsible for providing open access electricity transmission service on a non-discriminatory basis, planning transmission system additions, and ensuring the maintenance of adequate reserves of generation capacity.

*The Nuclear Regulatory Commission*

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay ("Humboldt Bay Unit 3"). NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and additional significant capital expenditures could be required in the future. For information about NRC matters affecting Diablo Canyon, including the status of the Utility's relicensing application see the information under the heading within MD&A entitled "Regulatory Matters−Diablo Canyon Nuclear Power Plant" in the 2012 Annual Report, which information is incorporated herein by reference.

*The Pipeline and Hazardous Materials Safety Administration*

The Utility also is subject to regulations adopted by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") that is within the United States Department of Transportation. The PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's pipeline transportation system and the shipment of hazardous materials. Through a certification with PHMSA, the CPUC is authorized to enforce the federal pipeline safety standards over intrastate natural gas pipelines, as well as any state pipeline safety requirements that do not conflict with the federal requirements, through penalties and/or injunctive relief.

*The National Transportation Safety Board*

The NTSB is an independent federal agency that is authorized to investigate pipeline accidents and certain transportation accidents that involve fatalities, substantial property damage, or significant environmental damage. The NTSB investigated the San Bruno accident and in August 2011 announced that it had determined the probable cause of the San Bruno accident placing the blame primarily on the Utility. The NTSB report recommended that the Utility take certain actions to improve the safety of its gas transmission system. The status of the Utility's implementation of the NTSB's recommendations is discussed under "Natural Gas Utility Operations" below.

***State Regulation***

*The California Public Utilities Commission*

The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electricity generation, and natural gas transportation and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC also enforces state laws that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas gathering, transmission, and distribution pipeline systems, and for the safe operation of such pipelines and equipment. The CPUC has adopted many rules and regulations to

implement state laws and policies, such as the laws relating to the development of renewable energy resources, demand response and public purpose programs, and the reduction of greenhouse gas ("GHG") emissions. The CPUC also has been delegated authority to enforce compliance with certain federal regulations related to the safety of natural gas facilities. The CPUC has authority to impose penalties for violating these state and federal laws, orders, or regulations of up to $50,000 per violation, per day. (See the discussion under the heading within MD&A entitled "Natural Gas Matters" in the 2012 Annual Report for information about the CPUC's pending enforcement proceedings against the Utility relating to the Utility's safety recordkeeping for its natural gas transmission system; the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density; and the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct that could have led to or contributed to the San Bruno accident, which discussion is incorporated herein by reference.)

Ratemaking for retail sales from the Utility's generation facilities is under the jurisdiction of the CPUC. To the extent that this electricity is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. In addition, the CPUC has general jurisdiction over most of the Utility's operations, and regularly reviews the Utility's performance, using measures such as the frequency and duration of outages. The CPUC also conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies. The CPUC has imposed conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates. These conditions relate to finance, human resources, records and bookkeeping, and the transfer of customer information. Among other conditions, the financial conditions provide that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, must be given first priority by PG&E Corporation's Board of Directors (known as the "first priority" condition). In addition, the Utility must maintain on average its CPUC-authorized utility capital structure, although it can request a waiver of this condition if an adverse financial event reduces the Utility's common equity component by 1% or more.

The CPUC also has adopted complex and detailed rules governing transactions between California's electricity and gas utilities and certain of their affiliates. The rules address the use of the utilities' names and logos by their affiliates, the separation of utilities and their affiliates, provision of utility information to affiliates, and energy procurement-related transactions between the utilities and their affiliates. The CPUC has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

*The California Energy Resources Conservation and Development Commission*

The California Energy Resources Conservation and Development Commission, commonly called the California Energy Commission ("CEC"), is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW, overseeing funding programs that support public interest energy research, advancing energy science and technology through research, development and demonstration, and providing market support to existing, new, and emerging renewable technologies. In addition, the CEC is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

*The California Air Resources Board*

The California Air Resources Board ("CARB") is the state agency charged with setting and monitoring GHG and other emission limits. The CARB also is responsible for adopting and enforcing regulations to meet the California Global Warming Solutions Act of 2006 ("AB 32"), which requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2013. In October 2011, the CARB adopted its final "cap-and-trade" regulations to help gradually reduce GHG emissions. In November 2012, the CARB held the first auction of GHG emission allowances under this "cap-and-trade" program. (For more information, see "Environmental Matters — Air Quality and Climate Change" below.)

***Other Regulation***

The Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. These permits include discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation facility and transmission line licenses, and NRC licenses. Some licenses and permits may be revoked or modified by the agency

that granted them if facts develop or events occur that differ significantly from the facts and projections assumed when they were granted. In addition, discharge permits and other approvals and licenses often have a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. (For more information, see "Environmental Matters — Water Quality" below.)

The Utility has franchise agreements with 292 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. The Utility has several franchise agreements that have a specified term of years, including an agreement with a large charter city.

The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas. Under these permits, authorizations, and licenses, the Utility has rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations.

***Competition in the Electricity Industry***

At the federal level, the FERC is charged with developing rules to encourage fair and efficient competitive wholesale electric markets by employing best practices in market rules and reducing barriers to trade between markets and among regions. (See "Regulatory Environment−Federal Regulation" above for a description of some of these rules.) The FERC also has authority to prevent accumulation and exercise of market power by assuring that proposed mergers and acquisitions of public utility companies and their holding companies are in the public interest and by addressing market power in jurisdictional wholesale markets through its new powers to establish and enforce rules prohibiting market manipulation. The FERC also has issued rules on the interconnection of generators to require regulated transmission providers, such as the Utility or the CAISO, to use standard interconnection procedures and a standard agreement for generator interconnections. These rules are intended to limit opportunities for electric transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage investment in generation and transmission.

At the state level, the California Legislature mandated the restructuring of the California electricity industry beginning in 1998 to allow customers of the California investor-owned electric utilities to purchase electricity from a service provider other than the regulated utilities (the ability to choose an energy provider is referred to as "direct access"). A market framework was established for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity through transactions conducted through the California Power Exchange ("PX"). As the 2000-2001 California energy crisis unfolded, direct access was suspended. The PX filed a petition for bankruptcy protection and now operates solely to reconcile remaining refund amounts owed and to make compliance filings as required by the FERC in the California refund proceeding, which is still pending at the FERC. (For information about the status of the California refund proceeding and the remaining disputed claims made by power suppliers in the Utility's bankruptcy proceeding that was precipitated by the energy crisis, see Note 13: Resolution of Remaining Chapter 11 Disputed Claims, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.)

Current California law provides only limited opportunities for customers who receive "bundled" electricity service (i.e., electricity, transmission and distribution services) to choose to purchase electricity directly from an energy service provider other than the three California investor-owned electric utilities. As authorized by California law enacted in October 2009, the CPUC has adopted a plan to reopen direct access on a limited and gradual basis to allow eligible customers of the three California investor-owned electric utilities to purchase electricity from independent electric service providers rather than from a utility. Effective April 2010, all qualifying non-residential customers became eligible to take direct access service subject to annual and absolute caps. It is estimated that the total amount of direct access that will be allowed in the Utility's service territory by the end of the four-year phase-in period will be equal to approximately 11% of the Utility's total annual retail sales at the end of the period, roughly the highest level that was reached before the CPUC suspended direct access. Further legislative action is required to exceed these limits.

In addition, the Utility's customers may, under certain circumstances, obtain power from a community choice aggregator ("CCA") instead of from the Utility. California law permits cities and counties and certain other public agencies to purchase and sell electricity for their local residents and businesses after they have registered as

CCAs. Under these arrangements, the Utility continues to provide distribution, metering, and billing services to the customers of the CCAs and remains the electricity provider of last resort for those customers. The law provides that a CCA can procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. Under the CPUC's rules, a surcharge is imposed on retail end-users of the CCA to prevent a shifting of costs to customers who continue to receive electricity from a utility. The law also authorizes the Utility to recover from each CCA any costs of implementing the program that are reasonably attributable to the CCA, and to recover from all customers any costs of implementing the program not reasonably attributable to a CCA. Over 90,000 customers in Marin County are now receiving commodity service from the Marin Energy Authority, a CCA.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, seek to acquire the Utility's distribution facilities. For example South San Joaquin Irrigation District ("SSJID") has applied to San Joaquin County Local Agency Formation Commission for the authority to provide electric distribution service in and around the cities of Manteca, Ripon and Escalon. SSJID has indicated that, if it receives the requested authority, it will seek to acquire the Utility's distribution facilities, either under a consensual transaction, or via eminent domain.

It is also possible that technological developments could pose challenges for traditional utilities. In particular, technology-related cost declines and sustained federal or state subsidies could make the combination of "distributed generation" and storage a viable, cost-effective alternative to the Utility's bundled electric service. In addition, the levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits at the full retail rate, are increasing.

Although the CPUC has established ratemaking mechanisms that allow the Utility to collect some non-bypassable or fixed charges from those who procure electricity from alternate sources, rates for the Utility's remaining customers could increase as alternative energy providers (CCAs or local government agencies) and alternative energy sources (self-generation and storage, distributed generation, electric vehicles) become more prevalent. Increasing rate pressure on remaining customers could, in turn, cause more customers to seek alternative energy providers or sources, further exacerbating the Utility's rate challenges.

***Competition in the Natural Gas Industry***

Under the FERC's rules, interstate natural gas pipeline companies are required to divide their services into separate gas commodity sales, transportation, and storage services and must provide transportation service whether or not the customer (often a local gas distribution company) buys the natural gas from these companies. The Utility's natural gas pipelines are located within the State of California and are exempt from most of the FERC's rules and regulations applicable to interstate pipelines; the Utility's pipeline operations are instead subject to the jurisdiction of the CPUC.

The CPUC divides the Utility's natural gas customers into two categories: "core" customers, who are primarily small commercial and residential customers, and "non-core" customers, who are primarily industrial, large commercial, and electric generation customers. Non-core customers have access to capacity rights for firm service on the Utility's natural gas pipeline, as well as interruptible (or "as-available") services. All services are offered on a nondiscriminatory basis to any creditworthy customer. This market structure has resulted in a robust wholesale gas commodity market at the Utility's "Citygate," which refers to the non-physical interconnection between the big "backbone" gas transmission system and the smaller downstream local transmission systems. The Utility's gas transmission and storage system has operated under the CPUC-approved "Gas Accord" market structure since 1998 which largely mimics the regulatory framework required by the FERC for interstate gas pipelines. (See "Ratemaking Mechanisms" below.)

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California, relative to the total delivered cost of natural gas from the southwestern United States. In general, when the total cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California increases relative to other competing natural gas sources, the Utility's market share of transportation services into southern California decreases. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

## Ratemaking Mechanisms

### *Overview*

The Utility’s rates for electricity and natural gas utility services are based on its costs of providing service (“cost-of-service ratemaking”). Before setting rates, the CPUC and the FERC conduct proceedings to determine the revenue requirements that the Utility is authorized to collect from its customers. The CPUC determines the Utility’s revenue requirements associated with electricity and natural gas distribution operations, electricity generation, and natural gas transportation and storage. The FERC determines the Utility’s revenue requirements associated with its electricity transmission operations.

Revenue requirements are designed to allow a utility an opportunity to recover its reasonable operating and capital costs of providing utility services as well as a return of, and a fair rate of return on its investment in utility facilities (“rate base”). Revenue requirements are primarily determined based on the Utility’s forecast of future costs. These costs include the Utility’s costs of electricity and natural gas purchased for its customers, operating expenses, administrative and general expenses, depreciation, taxes, and public purpose programs.

To develop retail rates, the revenue requirements are allocated among customer classes which are mainly residential, commercial, industrial, and agricultural. Specific rate components are designed to produce the required revenue. Rate changes become effective prospectively on or after the date of CPUC or FERC decisions. Most rate changes approved by the CPUC throughout the year are consolidated to take effect on the first day of the following year.

The Utility uses balancing accounts to keep track of its authorized revenue requirements, actual customer billings collected through rates, and actual costs incurred to provide electricity and natural gas services. Balances in all CPUC-authorized accounts are subject to review, verification audit, and adjustment, if necessary, by the CPUC. For more information regarding the Utility’s balancing accounts, see Note 3: Regulatory Assets, Liabilities and Balancing Accounts, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

While the CPUC generally uses cost-of-service ratemaking to develop revenue requirements and rates, it selectively uses incentive ratemaking, which bases rates on the extent to which the utilities meet objective or fixed standards or goals, such as energy efficiency goals, instead of on the cost of providing service.

### *Electricity and Natural Gas Distribution and Electricity Generation Operations*

#### *General Rate Cases*

The General Rate Case (“GRC”) is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility is authorized to collect from customers to recover the Utility’s anticipated business and operational costs related to its electricity and natural gas distribution and electricity generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The CPUC generally conducts a GRC every three years. Typical interveners in the Utility's GRC include the CPUC’s Division of Ratepayer Advocates and The Utility Reform Network. In November 2012, the Utility filed its 2014 GRC application with the CPUC for rates effective from 2014 through 2016. For more information see the heading within MD&A entitled “2014 General Rate Case” in the 2012 Annual Report, which information is incorporated herein by reference.

#### *Attrition Rate Adjustments*

The CPUC may authorize the Utility to receive annual increases for the years between GRCs in the base revenues authorized for the test year of a GRC in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. These adjustments are known as attrition rate adjustments. Attrition rate adjustments provide increases in the revenue requirements that the Utility is authorized to collect in rates for electricity and natural gas distribution and electricity generation operations.

*Cost of Capital Proceedings*

The CPUC authorizes the Utility's capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) and the authorized rates of return on each component that the Utility may earn on its electricity and natural gas distribution, natural gas transmission, and electricity generation assets. The authorized capital structure that was in effect through 2012 consisted of 52% equity, 46% long-term debt, and 2% preferred stock. Since 2008, the Utility's authorized cost of capital has been subject to an adjustment mechanism that is triggered in a particular year if the 12-month October-through-September average of the applicable Moody's Investors Service utility bond index increases or decreases by more than 100 basis points from the benchmark. If the adjustment mechanism is triggered, the Utility's authorized ROE beginning on the next January 1 st would be adjusted by one-half of the increase or decrease. This mechanism did not trigger a change in the Utility's authorized rates of return for 2012.

In December 2012, the CPUC issued a decision in the cost of capital proceeding that authorizes the Utility to maintain a capital structure consisting of 52% equity, 47% long-term debt, and 1% preferred stock beginning on January 1, 2013. (For more information see the section of MD&A entitled "2013 Cost of Capital Proceeding" in the 2012 Annual Report, which information is incorporated herein by reference.)

***Rate Recovery of Costs of Electricity Generation Resources***

*Overview*

California investor-owned electric utilities are required to use the principles of "least-cost dispatch" in managing electric generation resources to meet customer demand for electricity. The utilities are also responsible for procuring electricity required to meet customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electricity contracts. To accomplish this, each utility must submit a ten-year procurement plan to the CPUC for approval. Each procurement plan must be designed to reduce GHG emissions and use the State of California's preferred loading order to meet the forecasted demand (i.e., increases in future demand will be offset through energy efficiency programs, demand response programs, renewable generation resources, distributed generation resources, and new conventional generation). The CPUC approved the Utility's electricity procurement plan in January 2012 covering 2011 through 2020 and approved the Utility's GHG compliance instrument procurement plan in April 2012.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved electricity procurement plans without further after-the-fact reasonableness review. To the extent the Utility's electricity purchases are not in compliance with the CPUC-approved plan, costs associated with those purchases may be disallowed. The Utility recovers its electricity procurement costs through the Energy Resource Recovery Account ("ERRA"), a balancing account authorized by the CPUC. The ERRA tracks the difference between (1) billed and unbilled ERRA revenues and (2) electric procurement costs incurred under the Utility's authorized procurement plans. To determine the rates used to collect ERRA revenues, each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, hedging, and generation fuel expense and approves a forecasted revenue requirement. On December 20, 2012, the CPUC approved the Utility's forecast of 2013 procurement costs and associated revenue requirement. Changes in rates to reflect the approved revenue requirement became effective on January 1, 2013. (The CPUC may adjust a utility's retail electricity rates at any time when the forecasted aggregate over-collections or under-collections in the ERRA exceed five percent of its prior year electricity procurement revenues.) The CPUC also performs an annual compliance review to ensure that (1) the Utility prudently administered the contracts that were entered into in accordance with its CPUC-approved procurement plans, (2) utilized the principles of least-cost dispatch in managing its electric generation resources, and (3) prudently operated its own generation facilities.

*Costs Incurred Under New Power Purchase Agreements*

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, the renewable energy mandate, and resource adequacy requirements. The CPUC also authorized the Utility to recover fixed and variable costs associated with these contracts through the ERRA.

For new non-renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through either (1) a non-bypassable customer charge or (2) the allocation of the "net capacity costs" (i.e., contract price less energy revenues) to all "benefiting customers" in the Utility's service territory, including direct access customers and CCA customers under certain circumstances. The non-bypassable charge can be imposed from the date of signing a power purchase agreement and can last for ten

years from the date the new generation unit comes on line or for the term of the contract, whichever is less. Utilities are allowed to justify a cost recovery period longer than ten years on a case-by-case basis. If a utility uses the net capacity cost allocation method, the net capacity costs are allocated for the term of the contract. To use the net capacity allocation method, the CPUC must determine that a resource was needed to meet system or local area reliability needs for the benefit of all distribution customers. The CPUC can decide whether to require an energy auction for resources subject to the net capacity cost allocation.

For renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through the imposition of a non-bypassable charge on customers.

*Costs of Utility-Owned Generation Resource Projects*

The CPUC-authorized revenue requirements to recover the initial capital costs for utility-owned generation projects are recovered through the Utility Generation Balancing Account ("UGBA"), which tracks the difference between the CPUC-approved forecast of initial capital costs, adjusted from time to time as permitted by the CPUC, and actual costs. The initial revenue requirement for Utility-owned projects generally would begin to accrue in the UGBA as of the new facility's commercial operation date or the date a completed facility is transferred to the Utility, and would be included in rates on January 1 of the following year. The CPUC-authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for operating Utility-owned generation facilities are addressed in the Utility's GRC.

The Utility may recover any above-market costs associated with new utility-owned generation resources in a manner similar to the recovery of above-market costs for non-renewable generation purchases described above. The recovery of above-market costs is typically addressed in the CPUC order approving a specific utility-owned generation project.

***Electricity Transmission***

The Utility's electricity transmission revenue requirements and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two main sources of transmission revenues: (1) charges under the Utility's transmission owner tariff and (2) charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in 1998. These wholesale customers are referred to as existing transmission contract customers and are charged individualized rates based on the terms of their contracts. Other customers pay transmission rates that are established by the FERC in the Utility's transmission owner tariff rate cases. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and are collected from retail electric customers receiving bundled service.

*Transmission Owner Rate Cases*

The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility is authorized to recover for its electric transmission costs and to earn its return on equity is the transmission owner rate case ("TO rate case"). The Utility generally files a TO rate case every year. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. See the information within MD&A entitled "FERC Transmission Owner Rate Case" in the 2012 Annual Report, which information is incorporated herein by reference.

The Utility's transmission owner tariff includes several rate components. The primary component consists of base transmission rates intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense, and return on equity. The Utility derives the majority of the Utility's transmission revenue from base transmission rates. Another component consists of rates that reflect credits and charges from the CAISO for transmission revenues received by the CAISO for providing wholesale wheeling service (i.e., the transfer of electricity that is being sold in the wholesale market) to third parties using the Utility's transmission facilities and charges related to the cost of providing service to existing transmission contract customers under specific contracts. The CAISO also imposes a transmission access charge on the Utility for use of the CAISO-controlled electric transmission grid in serving its customers, which are recovered from the Utility's retail customers as part of transmission rates.

***Natural Gas***

*Gas Safety Rulemaking Proceeding*

The CPUC is conducting a rulemaking proceeding to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. As directed by the CPUC, in August 2011, the Utility filed its proposed pipeline safety enhancement plan to replace certain natural gas pipeline segments, install automatic or remote shut-off valves, and take other actions to modernize and upgrade its natural gas transmission system. On December 20, 2012, the CPUC approved the Utility's proposed plan but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs that the Utility forecasted it would incur over the first phase of the plan (2011 through 2014). See the information under the heading within MD&A entitled "Natural Gas Matters−CPUC Gas Safety Rulemaking Proceeding" in the 2012 Annual Report, which information is incorporated herein by reference.

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in a separate rate case called the gas transmission and storage ("GT&S") rate case. The CPUC's decision in the most recent GT&S rate case approved a settlement agreement, known as the Gas Accord V, which set the Utility's rates and associated revenue requirements for natural gas transmission and storage services from January 1, 2011 through December 31, 2014. (The Utility expects to file an application to begin the next GT&S rate case in September 2013.) A substantial portion of the authorized revenue requirements, primarily those costs allocated to core customers, continue to be assured of recovery through balancing account mechanisms and/or fixed reservation charges. The Utility's ability to recover the remaining revenue requirements continues to depend on throughput volumes, gas prices, and the extent to which non-core customers and other shippers contract for firm transmission services. This volumetric cost recovery risk associated with each function (backbone transmission, local transmission, and storage) is summarized below.

*Backbone Transmission.* The backbone transmission revenue requirement is recovered through a combination of firm two-part rates (consisting of fixed monthly reservation charges and volumetric usage charges) and as-available one-part rates (consisting only of volumetric usage charges). The mix of firm and as-available backbone services provided by the Utility continually changes. As a result, the Utility's recovery of its backbone transmission costs is subject to volumetric and price risk to the extent that backbone capacity is sold on an as-available basis. Core procurement entities (including core customers served by the Utility) are the primary long-term subscribers to backbone capacity. Core customers are allocated approximately 38% of the total backbone capacity on the Utility's system. Core customers pay approximately 69% of the costs of the backbone capacity that is allocated to them through fixed reservation charges.

*Local Transmission.* The local transmission revenue requirement is allocated approximately 66% to core customers and 34% to non-core customers. The Utility recovers the portion allocated to core customers through a balancing account, but the Utility's recovery of the portion allocated to non-core customers is subject to volumetric and price risk.

*Storage.* The storage revenue requirement is allocated approximately 51% to core customers, 37% to non-core storage service, and 12% to pipeline load balancing service. The Utility recovers the portion allocated to core customers through a balancing account, but the Utility's recovery of the portion allocated to non-core customers is subject to volumetric and price risk. The revenue requirement for pipeline load balancing service is recovered in backbone transmission rates and is subject to the same cost recovery risks described above for backbone transmission.

*Biennial Cost Allocation Proceeding*

Certain of the Utility's natural gas distribution costs and balancing account balances are allocated to customers in the CPUC's Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any over-collection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

*Natural Gas Procurement*

The Utility sets the natural gas procurement rate for core customers monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below), acquired on behalf of core customers, through its retail gas rates. (The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered through electricity balancing accounts.)

The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under the Core Procurement Incentive Mechanism ("CPIM"). Under the CPIM, the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

In January 2010, the CPUC approved a joint settlement agreement among the Utility, the CPUC's Division of Ratepayer Advocates, and The Utility Reform Network to incorporate a portion of hedging costs for core customers into the Utility's CPIM beginning November 1, 2010. The settlement agreement has an initial term of seven years, through October 2017, which can be extended by agreement of the parties. As a result, the settlement agreement permits the Utility to develop and implement a sustained core hedging program. (For more information, see Note 10: Derivatives, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference).

*Interstate and Canadian Natural Gas Transportation*

The Utility has a number of agreements with interstate and Canadian third-party transportation service providers to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These are governed by tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, and the applicable Canadian tariffs are approved by the Alberta Utilities Commission and the National Energy Board. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as electricity procurement costs. For more information, see the discussion below under "Natural Gas Utility Operations — Interstate and Canadian Natural Gas Transportation Services Agreements" below.

**Electric Utility Operations**

During 2012, the Utility made significant capital investments in its electric transmission and distribution infrastructure to extend the life of or replace existing infrastructure; to maintain and improve system reliability, safety, and customer service; to integrate more renewable energy resources; to increase capacity; and add new infrastructure to meet customer demand growth. The Utility improved the reliability of its system by adding emergency capacity at substations, increasing distribution system automation, upgrading poor performing circuits, performing targeted asset replacement, and improving service restoration processes. The Utility also has been working to accelerate pole replacement and maintenance of its overhead and underground electric facilities and to increase the use of wireless devices that allow the Utility to monitor the performance of the electric system and respond more quickly to power disruptions.

The Utility also substantially completed the installation of an advanced metering infrastructure throughout its service territory in 2012. As of December 31, 2012, the Utility has installed approximately 8.9 million advanced electric and gas meters. As permitted by CPUC rules, customers may choose not to have an advanced meter

installed. The new infrastructure uses SmartMeter ™ technology that can measure energy use in hourly or quarter-hourly increments, allow customers to track energy usage throughout the billing month and thus enable greater customer control over electricity costs. Usage data is collected through a wireless communications network and transmitted to the Utility's information system where the data is stored and used for billing and other Utility business purposes.

The Utility's advanced metering infrastructure supports the development of a "smart grid" in California, part of a nationwide effort to improve and modernize the nation's electric system by combining advanced communications and controls to create a responsive and resilient energy delivery network. In March 2012, the Utility began incorporating the latest "smart grid" technology in parts of its service territory by installing automated switches that reduce outage duration and the number of customers affected by outages. When an electrical outage occurs, these switches detect a short circuit, block power flow to the affected area, communicate with a central computer, and then quickly reroute power around the problem to keep as many customers powered as possible. Over the next several years, the Utility plans to undertake various "smart grid" projects and invest in "smart grid" technologies.

*Electricity Resources*

The Utility is required to maintain physical generating capacity adequate to meet its customers' load, including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio in the most cost-effective way. The following table shows the percentage of the Utility's total actual deliveries of electricity to customers in 2012 represented by each major electricity resource.

Total 2012 Actual Electricity Delivered – 76,205 GWh:

| | **Percent of Bundled Retail Sales** | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 23.3% | |
| Small Hydroelectric | 1.2% | |
| Large Hydroelectric | 9.7% | |
| Fossil fuel-fired | 8.3% | |
| Solar | 0.2% | |
| Total | | 42.7% |
| Qualifying Facilities [(1)] | | |
| Renewable | 4.4% | |
| Non-Renewable | 9.8% | |
| Total | | 14.2% |
| Irrigation Districts and Water Agencies | | |
| Small Hydroelectric | 0.3% | |
| Large Hydroelectric | 3.5% | |
| Total | | 3.8% |
| Other Third-Party Purchase Agreements | | |
| Renewable | 12.9% | |
| Large Hydroelectric | 0.4% | |
| Non-Renewable | 11.5% | |
| Total | | 24.8% |
| Others, Net [(2)] | | 14.5% |
| Total | | 100% |

(1) Electric utilities are required under federal law to purchase energy and capacity from independent power producers with generation facilities (20 MW or less) that meet the definition of a qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978. QFs primarily include co-generation facilities that produce combined heat and power and renewable generation facilities. For more information about the power purchase agreements that the Utility has entered into with QFs, see "QF Power Purchase Agreements," below.

(2) This amount is mainly comprised of net CAISO open market purchases, offset by transmission and distribution related system losses.

*Owned Generation Facilities*

At December 31, 2012, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---|---|---|---|
| Nuclear: | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric: | | | |
| Conventional | 16 counties in northern and central California | 106 | 2,683 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Hydroelectric subtotal: | | 109 | 3,895 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| CSU East Bay Fuel Cell | Alameda | 1 | 1.4 |
| SF State Fuel Cell | San Francisco | 2 | 1.6 |
| Fossil fuel-fired subtotal: | | 15 | 1,403 |
| Photovoltaic: | | 10 | 102 |
| Total | | 136 | 7,640 |

*Diablo Canyon Power Plant.* The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the twelve months period ended December 31, 2012, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 90%. The NRC operating license for Unit 1 expires in November 2024, and the NRC operating license for Unit 2 expires in August 2025. For more information on matters affecting Diablo Canyon, see the section of MD&A entitled "Regulatory Matters−Diablo Canyon Nuclear Power Plant" in the 2012 Annual Report, which information is incorporated herein by reference. The ability of the Utility to produce nuclear generation depends on the availability of nuclear fuel. The Utility has entered into various purchase agreements for nuclear fuel that are intended to ensure long-term fuel supply. For more information about these agreements, see Note 15: Commitments and Contingencies — Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

The following table outlines the Diablo Canyon power plant's refueling schedule for the next five years. The Diablo Canyon power plant refueling outages are typically scheduled every 20 months. The average length of a refueling outage over the last five years has been approximately 43.6 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Unit 1 | | | | | |
| Refueling | - | February | September | - | April |
| Duration (days) | - | 40 | 40 | - | 30 |
| Startup | - | March | November | - | May |
| Unit 2 | | | | | |
| Refueling | February | September | - | May | - |
| Duration (days) | 52 | 40 | - | 35 | - |
| Startup | March | November | - | June | - |

*Hydroelectric Generation Facilities.* The Utility's hydroelectric system consists of 109 generating units at 68 powerhouses, including the Helms pumped storage facility. Most of the Utility's hydroelectric generation units are classified as "large" hydro facilities, as their unit capacity exceeds 30 MW. The Helms pumped storage facility consists of three motor/generator units. During 2011, the Utility began inspections of all three units following reports of a significant failure of a similarly designed pumped storage generation unit in Austria that was apparently caused by cracks in the generator rotor poles due to metal fatigue. The Utility completed inspections and repairs on each of the three units and returned them to service in 2012.

All of the Utility's powerhouses are licensed by the FERC (except for three small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years. The Utility is in the process of renewing hydroelectric licenses associated with capacity of approximately 1,137 MW and surrendering the hydroelectric license associated with the Kilarc-Cow Creek Project which has a capacity of 5 MW. Although the original licenses associated with 880 MW of the 1,137 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 3,002 MW of hydroelectric power will expire between 2013 and 2047.

*Fossil Fuel-fired Generation Facilities.* The Utility's natural gas-fired generation facilities include the Colusa Generating Station, the Gateway Generating Station, and the Humboldt Bay generating station. In addition, the Utility owns and operates three fuel cell sites in the Bay Area. On December 20, 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California that would be acquired by the Utility no sooner than January 1, 2016.

*Photovoltaic Facilities.* In April 2010, the CPUC approved the Utility's five-year program for the development of up to 250 MW of solar photovoltaic ("PV") facilities to be owned and operated by the Utility, along with entering into power purchase agreements for an additional 250 MW of PV facilities to be developed by third parties. Under the PV program, Utility-owned PV facilities with an aggregate of 100 MW are operational, and an additional 50 MW are under construction and expected to become operational in 2013. The operational PV facilities include, the Five Points solar station (15 MW), the Westside solar station (15 MW), the Stroud solar station (20 MW), the Huron solar station (20 MW), the Cantua solar station (20 MW), and the Giffen solar station (10 MW). All of these facilities are located in Fresno County. The PV facilities under construction are the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). The Gates and West Gates solar stations are located in Fresno County; the Guernsey solar station is located in Kings County.

In December 2012, the Utility sought CPUC approval to terminate the PV program early. If approved, the Utility will not pursue the development of the remaining 100 MW of Utility-owned PV facilities over the remaining two years of the program, but instead will procure this capacity through the CPUC's Renewable Auction Mechanism ("RAM") process. Additionally, the Utility proposed to solicit the remaining 152 MW of capacity to be provided under power purchase agreements through the RAM process rather than through the PV program.

*Generation Resources from Third Parties*

*QF Power Purchase Agreements.* Under the Public Utility Regulatory Policies Act ("PURPA") of 1978 electric utilities are required to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility ("QF"). In June 2011, the FERC approved the California investor-owned utilities' joint application to terminate their obligation under PURPA to purchase QF energy and capacity from facilities exceeding 20 MW. QFs primarily include co-generation facilities that produce combined heat and power and renewable generation facilities. As of December 31, 2012, the Utility had power purchase agreements with 180 operating QFs for approximately 3,000 MW of capacity. The majority of this capacity is from cogeneration facilities and the remainder is from renewable generation facilities. Agreements for approximately 2,700 MW expire at various dates between 2013 and 2028. QF power purchase agreements for approximately 300 MW have no specific expiration dates and will terminate only when the owner of the QF exercises its termination option. No single QF accounted for more than 5% of the Utility's 2012 electricity deliveries.

*Irrigation Districts and Water Agencies.* The Utility also has entered into agreements with various irrigation districts and water agencies to purchase hydroelectric power. These agreements require the Utility to make semi-annual fixed minimum payments as well as variable payments based on the operating and maintenance costs incurred by the irrigation districts and water agencies. These contracts will expire on various dates between 2013 and 2030.

*Other Third-Party Power Purchase Agreements* . The Utility has entered into several power purchase agreements for renewable and conventional generation resources, including tolling agreements and resource adequacy agreements.

For more information regarding the Utility's power purchase agreements, see Note 15: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

*Renewable Generation Resources*

Renewable generation resources include bioenergy such as biogas and biomass, small hydroelectric, wind, solar, and geothermal energy. California's Renewables Portfolio Standard ("RPS") program gradually increases the amount of renewable energy that load-serving entities, such as the Utility, must deliver to their customers from an average of at least 20% of their total retail sales in the years 2011-2013 to 33% of their total retail sales in 2021 and thereafter. For more information regarding the new RPS program, see the section of MD&A entitled "Environmental Matters – Renewable Energy Resources" in the 2012 Annual Report, which information is incorporated herein by reference.

During 2012, most renewable energy deliveries resulted from third party power purchase agreements and QF agreements. Additional renewable resources included the Utility's small hydroelectric and solar facilities and certain irrigation district contracts (small hydroelectric facilities). (Under California law only small hydroelectric generation resources (30 MW or less) can qualify as a renewable resource for purposes of meeting the RPS mandate. Most of the Utility's hydroelectric generating units have a capacity in excess of the 30-MW threshold and do not qualify as RPS-eligible resources.)

Total 2012 renewable deliveries are stated in the table below.

| Type | GWh | % of Bundled Load |
|---|---|---|
| Biopower | 3,373 | 4.4% |
| Geothermal | 3,803 | 5.0% |
| Wind | 4,338 | 5.7% |
| Small Hydroelectric | 1,812 | 2.4% |
| Solar | 1,171 | 1.5% |
| Total | 14,497 | 19.0% |

For more information regarding the Utility's renewable energy contracts, see Note 15: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

***Electricity Transmission***

At December 31, 2012, the Utility owned approximately 18,100 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV. The Utility also operated 91 electric transmission substations with a capacity of approximately 60,800 MVA. The Utility's electric transmission system is interconnected with electric power systems in the WECC, which includes many western states, Alberta and British Columbia, Canada, and parts of Mexico.

The CAISO, which is regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. The CAISO also is responsible for ensuring that the reliability of the transmission system is maintained. The Utility acts as its own scheduling coordinator to schedule electricity deliveries to the transmission grid. The Utility also acts as a scheduling coordinator to deliver electricity produced by several governmental entities to the transmission grid under contracts

the Utility entered into with these entities before the CAISO commenced operation in 1998. In addition, under the mandatory reliability standards implemented by the FERC, all users, owners, and operators of the transmission system, including the Utility, are also responsible for maintaining reliability through compliance with the reliability standards. See the discussion of reliability standards under "The Utility's Regulatory Environment — Federal Regulation" above.

During 2012, the Utility upgraded several critical substations and re-conductored some transmission lines to improve maintenance and operating flexibility, reliability and safety, including the installation or replacement of 9 transmission substation banks. The Utility expects to undertake various additional transmission projects over the next few years to upgrade and expand the Utility's transmission system and increase capacity in order to accommodate system load growth, to secure access to renewable generation resources, to replace aging or obsolete equipment, and to improve system reliability.

***Electricity Distribution***

The Utility's electricity distribution network consists of approximately 141,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 58 transmission-switching substations, and 601 distribution substations. The Utility's distribution network interconnects with the Utility's transmission system primarily at transmission switching substations and distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers. The distribution substations serve as the central hubs of the Utility's electricity distribution network and consist of transformers, voltage regulation equipment, protective devices, and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or other facilities to entities, such as municipal and other utilities, that then resell the electricity.

In 2012, the Utility replaced more than 130,000 feet of underground cable, primarily in San Francisco and Oakland, replaced 98,000 feet of overhead wire, and installed or replaced 39 distribution substation transformer banks to improve reliability and provide capacity to accommodate growing demand. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2013.

***Electricity Operating Statistics***

The following table shows certain of the Utility's operating statistics from 2008 to 2012 for electricity sold or delivered, including the classification of revenues by type of service.

| | 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Customers (average for the year) | 5,214,170 | 5,188,638 | 5,155,724 | 5,137,240 | 5,129,427 |
| Deliveries (in GWh) [1] | 86,113 | 81,255 | 79,634 | 72,385 | 74,783 |
| Revenues (in millions): | | | | | |
| Residential | $ 4,953 | $ 4,778 | $ 4,795 | $ 4,759 | $ 4,656 |
| Commercial | 4,735 | 4,732 | 4,823 | 4,538 | 4,413 |
| Industrial | 1,408 | 1,379 | 1,424 | 1,392 | 1,400 |
| Agricultural | 901 | 692 | 736 | 770 | 727 |
| Public street and highway lighting | 79 | 77 | 79 | 74 | 75 |
| Other | (11) | 94 | (1,178) | (1,700) | (863) |
| Subtotal | 12,065 | 11,752 | 10,679 | 9,833 | 10,408 |
| Regulatory balancing accounts | (51) | (151) | (35) | 424 | 330 |
| **Total electricity operating revenues** | $12,014 | $11,601 | $ 10,644 | $ 10,257 | $ 10,738 |
| Other Data: | | | | | |
| Average annual residential usage (kWh) | 5,961 | 6,799 | 6,843 | 6,953 | 7,007 |
| Average billed revenues (per kWh): | | | | | |
| Residential | $ 0.1594 | $ 0.1548 | $ 0.1560 | $ 0.1524 | $ 0.1480 |
| Commercial | 0.1449 | 0.1441 | 0.1468 | 0.1377 | 0.1296 |
| Industrial | 0.917 | 0.951 | 0.988 | 0.940 | 0.867 |
| Agricultural | 0.1458 | 0.1475 | 0.1451 | 0.1327 | 0.1300 |
| Net plant investment per customer | $ 4,919 | $ 5,045 | $ 4,728 | $ 4,336 | $ 3,994 |

(1) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

## Natural Gas Utility Operations

During 2012, the Utility has taken many immediate and longer-term steps to improve the safety and reliability of its natural gas transmission system, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's pipeline safety enhancement plan ("PSEP"), approved by the CPUC in December 2012, to meet the new, industry-wide safety standards for gas transmission systems. (See the information within MD&A under the heading "Natural Gas Matters" in the 2012 Annual Report, which information is incorporated herein by reference.)

In 2012, as part of the PSEP pipeline modernization program, the Utility confirmed the strength of 202 miles of transmission pipeline through hydrostatic pressure tests or records verification, installed 46 automated or remote-controlled valves, replaced 40 miles of transmission pipeline, and retrofitted 78 miles of transmission pipeline to accommodate in-line inspection tools. Since work on the program began in 2011, the Utility has also collected and digitized more than 3.5 million pipeline records, which includes validating the Maximum Allowable Operating Pressure ("MAOP") for more than 89 percent of its gas transmission system (and 100 percent of the 2,088 miles of the Utility's transmission pipelines in populated areas).

The Utility is also improving operations by utilizing modern tools and technologies. In 2012, the Utility began demonstrating a new car-mounted natural gas leak detection device, which is much more sensitive than traditional instruments. The Utility also began using an advanced hand-held leak-detection instrument that uses infrared technology to pinpoint methane gas without false alarms from other gases. This technology can detect and grade leaks at the same time. In addition, the Utility improved its supervisory controls and data acquisition system ("SCADA") to better detect pipeline leaks and breaks and improved its integrity management program, including incorporating new analysis tools to identify and assess risks to pipeline integrity.

For the distribution system, the Utility has implemented a new distribution integrity management program designed to enhance operations and improve the overall safety of the gas distribution system. In 2012, the Utility replaced 23 miles of Aldyl-A plastic pipeline and identified another 150 miles to be replaced over the next two years. It also updated the geographic information system with information on more than 5,500 miles of Aldyl-A pipeline, including additional pipeline and service attribute information. The Utility also completed additional distribution leak surveys in 2012, in addition to complying with regular distribution leak survey requirements.

Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011. In the first half of 2012, the Utility was able to officially close out four of the twelve NTSB recommendations. In January 2013, the Utility requested closure on three more recommendations. The Utility continues to make significant progress on the remaining longer-term recommendations, and the NTSB stated in September 2012 that the Utility's progress was acceptable.

In December 2012, the CPUC accepted the gas safety plans submitted by each gas corporation in California, including the Utility, to describe each gas corporation's programs, plans, and initiatives, to increase the safety and reliability of their natural gas operations. The plans were submitted in compliance with California Senate Bill 705, enacted in October 2011, which requires each gas corporation subject to CPUC jurisdiction to develop and implement a plan for the safe and reliable operation of its gas pipeline system. The new law required the CPUC to review the plans and accept, modify, or reject each plan by December 31, 2012. The CPUC has ordered the Utility, as well as the other gas corporations, to submit modifications to their plans by June 2013 and to continually review, revise and update their plans as required by emerging issues, industry practices, and state and federal regulators.

### *Natural Gas System Assets*

The Utility owns and operates an integrated natural gas transportation, storage, and distribution system that includes most of northern and central California. At December 31, 2012, the Utility's natural gas system consisted of approximately 42,400 miles of distribution pipelines, approximately 6,400 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations which receive, store and move natural gas through the Utility's pipelines. (The Utility has incurred significant environmental liabilities related to some of its compressor stations. See "Environmental Matters" below.) The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas

fields to the Utility's local transmission and distribution systems. The Utility's Line 300 interconnects with pipeline systems located in the U.S. Southwest and the Rocky Mountains that are owned by third parties (Transwestern Pipeline Company, El Paso Natural Gas Company, Questar Southern Trails Pipeline Company, and Kern River Pipeline Company). Line 300 has a receipt capacity of approximately 1.1 Bcf per day. The Utility's Line 400/401 interconnects at the California-Oregon border with the pipeline systems owned by Gas Transmission Northwest Corporation ("GTN") and Ruby Pipeline, LLC. This line has a receipt capacity at the border of approximately 2.2 Bcf per day. Through interconnections with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility also is supplied by natural gas fields in California.

The Utility owns and operates three underground natural gas storage fields connected to the Utility's transmission and storage system and has a 25% interest in the new Gill Ranch Storage Field. These storage fields and the Utility's Gill Ranch share have a combined firm capacity of approximately 48.7 Bcf. In addition, three independent storage operators are interconnected to the Utility's northern California transportation system.

***Natural Gas Services***

The CPUC divides the Utility's on-system natural gas customers into two categories for the purpose of determining service reliability: core and non-core customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and small commercial natural gas customers. The non-core customer class is comprised of industrial, large commercial, and electric generation natural gas customers. In 2012, core customers represented more than 99% of the Utility's total natural gas customers and 36% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total natural gas customers and 64% of its total natural gas deliveries. In addition to deliveries discussed above, the Utility delivers gas to off-system customers ( *i.e* ., outside of the Utility's service territory) and to third-party natural gas storage customers.

The Utility provides natural gas transportation services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas procurement service (i.e. , natural gas supply) from either the Utility or alternate energy service providers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, over 96% of core customers, representing over 83% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to large non-core customers such as electricity generators, QF co-generators, enhanced oil recovery customers, refiners, and other large non-core customers. However, some smaller non-core customers are permitted to elect to receive core service, including procurement service, from the Utility if they agree to receive such service for a minimum of five years. Core service to non-core customers is subject to these restrictions to protect core procurement customers from price increases that could otherwise result if the Utility incurred costs to reinforce its pipeline system and take other measures to provide core service reliability on a short-term basis to serve new load from non-core customers.

The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers.

The Utility has regulatory balancing accounts for core customers designed to ensure that the Utility's results of operations over the long term are not affected by weather variations, conservation, energy efficiency measures, or changes in their consumption levels. The Utility's results of operations can be affected, however, by non-core consumption levels because there are fewer regulatory balancing accounts related to non-core customers. Approximately 97% of the Utility's natural gas distribution base revenues are recovered from core customers and the remainder from non-core customers.

*Natural Gas Supplies*

The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated generally based on market conditions. During 2012, the Utility purchased approximately 247,792 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier

represented approximately 10% of the total natural gas volume the Utility purchased during 2012.

*Interstate and Canadian Natural Gas Transportation Services Agreements*

The Utility has a number of arrangements with interstate and Canadian third-party transportation service providers to serve core customers' service demands. The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by GTN, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility, the largest firm shipper on GTN's pipeline, has two firm transportation agreements with GTN for these services. In addition, the Utility has firm transportation agreements with Ruby Pipeline, LLC to transport this gas from the U.S Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border, and firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport this natural gas from supply points in this region to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona.

*Natural Gas Deliveries*

The total volume of natural gas delivered to on-system customers during 2012 was approximately 945 MMDth. The following table shows the percentage of the Utility's total 2012 natural gas deliveries represented by each of the Utility's major customer classes.

| | |
|---|---|
| Residential Customers | 20% |
| Transport-only Customers (non-core) | 75% |
| Commercial Customers | 5% |

The California Gas Report is prepared by the California electric and natural gas utilities to present an outlook for natural gas requirements and supplies for California over a long-term planning horizon. It is prepared in even-numbered years followed by a supplemental report in odd-numbered years. The 2012 California Gas Report forecasts average annual growth in the Utility's natural gas deliveries (for core customers and non-core transportation) of approximately 0.3% for the years 2010 through 2030. The natural gas requirements forecast is subject to many uncertainties, and there are many factors that can influence the demand for natural gas, including weather conditions, level of economic activity, conservation, price, and the number and location of electricity generation facilities.

*Natural Gas Operating Statistics*

The following table shows the Utility's operating statistics from 2008 through 2012 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

| | 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Customers (average for the year) | 4,353,278 | 4,327,407 | 4,295,741 | 4,271,007 | 4,269,165 |
| Gas purchased (MMcf) | 247,792 | 279,157 | 270,228 | 264,314 | 260,315 |
| Average price of natural gas purchased | $ 2.45 | $ 3.69 | $ 4.07 | $ 3.57 | $ 7.51 |
| Bundled gas sales (MMcf): | | | | | |
| Residential | 185,376 | 201,109 | 195,195 | 195,217 | 198,699 |
| Commercial | 47,341 | 52,230 | 53,921 | 57,550 | 63,934 |
| Total | 232,717 | 253,339 | 249,116 | 252,767 | 262,633 |
| Revenues (in millions): | | | | | |
| Bundled gas sales: | | | | | |
| Residential | $ 1,852 | $ 2,089 | $ 1,991 | $ 1,953 | $ 2,574 |
| Commercial | 383 | 464 | 474 | 496 | 792 |
| Regulatory balancing accounts | 221 | 295 | 305 | 289 | 221 |
| Other | 66 | 102 | 49 | 55 | (30) |
| Bundled gas revenues | 2,522 | 2,950 | 2,819 | 2,793 | 3,557 |
| Transportation service only revenue | 499 | 400 | 377 | 349 | 333 |
| Operating revenues | $ 3,021 | $ 3,350 | $ 3,196 | $ 3,142 | $ 3,890 |
| Selected Statistics: | | | | | |
| Average annual residential usage (Mcf) | 45 | 49 | 48 | 48 | 49 |
| Average billed bundled gas sales revenues per Mcf: | | | | | |
| Residential | $ 9.99 | $ 10.39 | $ 10.20 | $ 10.00 | $ 12.95 |
| Commercial | 8.09 | 8.89 | 8.79 | 8.62 | 12.38 |
| Net plant investment per customer | $ 1,696 | $ 1,721 | $ 1,637 | $ 1,557 | $ 1,344 |

**Public Purpose and Customer Programs**

California law has historically required the CPUC to authorize certain levels of funding for programs related to energy efficiency, research and development, and renewable energy resources through the collection of an electric public goods charge. The legislation authorizing the public goods charge expired on January 1, 2012. The CPUC has ordered the Utility to continue to collect in electric rates the amounts that were previously funded through the public goods charge for energy efficiency and established an energy program investment charge to support ongoing energy efficiency and research and development. Gas public interest research continues to be funded through the gas public purpose program surcharge. California law requires the CPUC to authorize funding for the California Solar Initiative and other self-generation programs, as discussed under “Self-Generation Incentive Program and California Solar Initiative,” below. Additionally, the CPUC has authorized funding for energy savings assistance and demand response programs. For 2012, the Utility collected authorized revenue requirements of $688 million from electric customers and $169 million from gas customers to fund public purpose and other programs.

*Energy Efficiency Programs*

The Utility's energy efficiency programs are designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances, other energy-using equipment and energy management products to meet energy savings goals in California. The CPUC has authorized a total of $823 million to fund the Utility's 2013 and 2014 energy efficiency programs, including programs administered by the Marin Energy Authority, a CCA, and a regional network of San Francisco Bay area cities and counties.

On December 20, 2012, the CPUC approved a new energy efficiency incentive mechanism to reward the Utility and other California energy utilities for the successful implementation of their 2010-2012 energy efficiency programs. The mechanism provides each utility with an earnings rate composed of a 5% management fee based on qualified program expenditures and an additional performance bonus of up to 1%. The Utility's earnings rate for the 2010-2012 energy efficiency program cycle is 5.68%. The CPUC awarded the Utility $21 million for the successful implementation of the Utility's 2010 energy efficiency programs. The CPUC decision also established the process that is expected to apply to incentive claims for program years 2011 and 2012. After the CPUC completes its audit of the utilities' 2011 program expenditures, the utilities must file their incentive claims in the third quarter of 2013 for approval by the CPUC in the fourth quarter of 2013. Similarly, the utilities will file their incentive claims based on the CPUC-audited 2012 program expenditures in the third quarter of 2014 for approval by the CPUC in the fourth quarter of 2014.

It is uncertain what form of incentive ratemaking the CPUC will establish and what amount, if any, the Utility will be authorized to earn for future energy efficiency programs.

*Demand Response Programs*

Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. In April 2012, the CPUC authorized the Utility to collect $192 million to fund its 2012-2014 demand response programs. Due to the timing of the decision, the CPUC authorized the Utility to recover both 2012 and 2013 program costs through customer rates collected in 2013.

*Self-Generation Incentive Program and California Solar Initiative*

The Utility administers the self-generation incentive program authorized by the CPUC to provide incentives to electricity and gas customers who install certain types of clean or renewable distributed generation and energy storage resources that meet all or a portion of their onsite energy usage. In December 2011, the CPUC approved continuing annual funding for the self-generation incentive program of $36 million through 2014, with any carryover funds to be administered through 2015. The Utility also administers the California Solar Initiative in its service territory. The CPUC has authorized the Utility to collect approximately $1.1 billion from 2007 through 2016 to fund customer incentives for the installation of retail solar energy projects to serve onsite load, as well as to fund research, development, and demonstration activities, and administration expenses. The current overall objective of this initiative is to install 3,000 MW (through both California investor-owned electric utilities and municipal electric utilities) through 2016.

*Low-Income Energy Efficiency Programs and California Alternate Rates for Energy*

The CPUC has authorized the Utility to collect approximately $469 million to support the Utility's energy efficiency programs for low-income and fixed-income customers over 2012 through 2014. The Utility also provides a discount rate called the California Alternate Rates for Energy ("CARE") for low-income customers. This rate subsidy is paid for by the Utility's other customers. During any given year, the extent of the subsidy for customers collectively depends upon the number of customers participating in the program and their actual energy usage. In 2012, the amount of this subsidy was approximately $851 million. The CPUC also authorized the Utility to recover approximately $45 million in administrative costs relating to the CARE subsidy through 2014.

**Environmental Matters**

The Utility is subject to a number of federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public.  These laws and requirements relate to a broad range of activities, including the following:

- the discharge of pollutants into the air, water, and soil;
- the transportation, handling, storage and disposal of spent nuclear fuel;
- the identification, generation, storage, handling, transportation, treatment, disposal, record keeping, labeling, reporting, remediation and emergency response in connection with hazardous and radioactive substances;
- the reporting and reduction of carbon dioxide ("CO2") and other GHG emissions; and
- the environmental impacts of land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions.  These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations.  To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify, or replace equipment, acquire permits and/or emission allowances or other emission credits for facility operations and clean-up, or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility's wastes may have been disposed.

The Utility's estimated costs to comply with environmental laws and regulations are based on current estimates and assumptions that are subject to change.  In addition, the Utility is likely to incur costs as it develops
and implements strategies to mitigate the impact of its operations on the environment, including climate change and its foreseeable impact on the Utility's future operations.  The actual amount of costs that the Utility will incur is subject to many factors, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, the availability of recoveries or contributions from third parties, and the development of market-based strategies to address climate change.  Generally, the Utility has recovered the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review.  Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a special ratemaking mechanism described under "Recovery of Environmental Remediation Costs" below.

***Air Quality and Climate Change***

The Utility's electricity generation plants, natural gas pipeline operations, fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes.  These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, sulfur dioxide ("SO2"), nitrogen oxide ("NOx") and particulate matter.

*Federal Regulation* .  At the federal level, the U.S. Environmental Protection Agency ("EPA") is charged with implementation and enforcement of the Clean Air Act.  Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted..  In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions, including establishing an annual GHG reporting requirement.

*State Regulation.*   AB 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32.  The CARB established a state-wide GHG 1990 emissions baseline of 427 million metric tons of CO2 (or its equivalent) to serve as the 2020 emissions limit for the state of California.  The CARB has approved various regulations to implement AB 32, including a state-wide, comprehensive "cap and trade" program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by the major sources of GHG emissions.

The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors.  The next two-year compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively

covering all the capped sectors until 2020. Each year the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties on the secondary market for trading GHG allowances. The CARB's first quarterly auction was held on November 14, 2012. Emitters (also known as covered entities) are required to obtain and surrender allowances equal to the amount of their GHGs emissions within a particular compliance period. Emitters may also meet up to 8% of their compliance obligation through the purchase of "offset credits" which represent GHG emissions abatement achieved in sectors that are not subject to the cap. For more information about the cap-and trade program, see the section of MD&A entitled "Environmental Matters" in the 2012 Annual Report, which information is incorporated herein by reference.

Increasing use of renewable energy supplies also is expected to help reduce GHG emissions in California. In April 2011, the California Governor signed legislation that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy delivered to their customers to at least 33% of the total amount of electricity retail sales by 2020. (See "Electricity Resources" above.) In December 2011, the CPUC approved various regulations to implement the new law, including the establishment of renewable energy targets for each compliance period. (For more information, see "Renewable Generation Resources" above.)

*Climate Change Mitigation and Adaptation Strategies.* During 2012, the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to develop its strategy to plan for the actions that it will need to take to adapt to the likely impacts that climate change will have on the Utility's future operations. With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme and frequent hot weather events. Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. This impact could, in turn, affect the Utility's hydroelectric generation. At this time, the Utility does not anticipate that reductions in Sierra Nevada snowpack will have a significant impact on its hydroelectric generation, due in large part to its adaptation strategies. For example, one adaptation strategy the Utility is developing is a combination of operating changes that may include, but are not limited to, higher winter carryover reservoir storage levels, reduced conveyance flows in canals and flumes in response to an increased portion of precipitation falling as rain rather than snow, and reduced discretionary reservoir water releases during the late spring and summer. If the Utility is not successful in fully adapting to projected reductions in snowpack over the coming decades, it may become necessary to replace some of its hydroelectric generation with electricity from other sources, including GHG-emitting natural gas-fired power plants.

With respect to natural gas operations, safety-related pipeline hydrotesting, as well as normal pipeline maintenance, releases the GHG methane to the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression. In addition, the Utility continues to replace a substantial portion of its older cast iron and steel gas mains with new pipe, which reduces leakage.

The Utility believes its strategies to reduce GHG emissions—such as energy efficiency and demand response programs, infrastructure improvements, and the support of renewable energy development—are also effective strategies for adapting to the expected increased demand for electricity in extreme hot weather events likely to result from climate change. PG&E Corporation and the Utility are also assessing the benefits and challenges associated with various climate change policies and identifying how a comprehensive program can be structured to mitigate overall costs to customers and the economy as a whole while ensuring that the environmental objectives of the program are met.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. As a result of the time necessary for a thorough, third-party verification of the Utility's GHG emissions, emissions data for 2011 are the most recent data available. Since 2009, the Utility has complied with AB 32's annual GHG emissions reporting requirements, reporting combustion emissions from its electric generation facilities and natural gas compressor stations to the CARB. (For information about the sources of electric generation that the Utility delivered to customers in 2012, see "Electric Utility Operations− Electricity Resources" above.) Consistent with Utility practice since 2002, the Utility also voluntarily reported its 2011 GHG emissions to The Climate Registry ("TCR"), a non-profit organization that has a reporting and measurement standard applicable to most industry sectors across North America. Reporting to TCR enables the Utility to publicly report GHG emissions not covered by mandatory reporting requirements. The Utility's third-party verified voluntary GHG

inventory for 2011 totaled more than 50 million metric tonnes of CO2-equivalent (“CO2-e”), which includes approximately 33 million metric tonnes CO2-e from customer natural gas use.

Beginning with its 2010 emissions, the Utility also reported the GHG emissions from its facilities and operations to the EPA under its mandatory reporting requirements. PG&E Corporation and the Utility also publish third-party-verified GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

***2011 Emissions Reported to the California Air Resources Board***

For its 2011 emissions, the Utility began reporting the GHG emissions from natural gas supplied to customers and the fugitive emissions from its natural gas distribution system and compressor stations. The following table shows the GHG emissions data the Utility reported to the CARB under AB 32.

| **Source** | **Amount (metric tonnes CO2 – equivalent)** |
|---|---|
| Fossil Fuel-Fired Plants (1) | 2,025,543 |
| Natural Gas Compressor Stations (2) | 258,446 |
| Distribution Fugitive Natural Gas Emissions | 224,298 |
| Customer Natural Gas Use (3) | 39,049,732 |
| Total | 41,558,019 |

(1) Includes nitrous oxide (“N2O”) and methane (“CH4”) emissions from the Utility’s generating stations; does not include de minimis emissions.
(2) Includes compressor stations emitting more than 25,000 metric tonnes of CO2-e annually; does not include de minimis emissions.
(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility’s distribution system, with the exception of gas delivered to other natural gas local distribution companies. This figure does not represent the Utility’s compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities as calculated by the CARB.

***Benchmarking GHG Emissions for Delivered Electricity***

The Utility’s third-party-verified CO2 emissions rate associated with the electricity delivered to customers in 2011 was 393 pounds of CO2 per MWh. The Utility’s 2011 emissions rate as compared to the national and California averages for electric utilities is shown in the following table:

| | **Amount (Pounds of CO2 per MWh)** |
|---|---|
| U.S. Average (1) | 1,216 |
| California’s Average (1) | 659 |
| Pacific Gas and Electric Company (2) | 393 |

(1) Source: Environmental Protection Agency eGRID 2012 Version 1.0, which contains year 2009 information configured to reflect the electric power industry's current structure as of May 10, 2012. This is the most up-to-date information available from EPA.

(2) Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility’s total emissions and the Utility’s emission rate for delivered electricity.

***Emissions Data for Utility-Owned Generation***

In addition to GHG emissions data provided above, the table below sets forth information about the GHG and other emissions from the Utility’s owned generation facilities. The Utility’s owned generation (primarily nuclear and hydroelectric facilities) comprised more than 40% of the Utility’s delivered electricity in 2011. The Utility’s fossil fuel-fired generation comprised approximately 6% of the Utility’s delivered electricity in 2011.

| | 2011 | 2010 |
|---|---|---|
| Total NOx Emissions (tons) | 144 | 904 |
| NOx Emissions Rates (pounds/MWh) | | |
| Fossil Fuel-Fired Plants | 0.06 | 0.49 |
| All Plants | 0.008 | 0.06 |
| Total SO2 Emissions (tons) | 12 | 42 |
| SO2 Emissions Rates (pounds/MWh) | | |
| Fossil Fuel-Fired Plants | 0.005 | 0.023 |
| All Plants | 0.0007 | 0.003 |
| Total CO2 Emissions (metric tons) | 2,024,206 | 1,545,892 |
| CO2 Emissions Rates (pounds/MWh) | | |
| Fossil Fuel-Fired Plants | 875 | 943 |

| | | |
|---|---|---|
| All Plants | 126 | 106 |
| Other Emissions Statistics | | |
| Sulfur Hexafluoride (“SF6”) Emissions | | |
| Total SF6 Emissions (metric tons CO2-equivalent) | 70,052 | 69,066 |
| SF6 Emissions Leak Rate | 1.7% | 1.8% |

***Water Quality***

Section 316(b) of the federal Clean Water Act requires that cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. On April 20, 2011, the EPA published draft regulations that propose specific reductions for impingement (which occurs when larger organisms are caught on water filter screens) and provide a case-by-case site specific assessment to establish compliance requirements for entrainment (which occurs when organisms are drawn through the cooling water system). The proposed site specific assessment allows for the consideration of a variety of factors including social costs and benefits, energy reliability, land availability, and non-water quality adverse impacts. The draft regulations were subject to public comment. In June 2012, the EPA issued a Notice of Data Availability proposing changes to the draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. The EPA is required to issue final regulations by July 2013.

On May 4, 2010, the California Water Resources Control Board ("California Water Board") adopted a policy on once-through cooling. The policy, effective October 1, 2010, generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities by at least 85%. However, with respect to the state's nuclear power generation facilities, the policy allows other compliance measures to be taken if the costs to install cooling towers are "wholly out of proportion" to the costs considered by the California Water Board in developing its policy. The policy also allows other compliance measures to be taken if the installation of cooling towers would be "wholly unreasonable" after considering non-cost factors such as engineering and permitting constraints and adverse environmental impacts. The Utility believes that the costs to install cooling towers at Diablo Canyon, which could be as much as $4.5 billion, will meet the "wholly out of proportion" test. The Utility also believes that the installation of cooling towers at Diablo Canyon would be "wholly unreasonable." The policy also established a nuclear review committee to evaluate the feasibility and cost of alternative technologies for nuclear plants. The committee's consultant, Bechtel, must complete an assessment for the California Water Board's review by October 2013. Upon review of the feasibility assessment, if the California Water Board does not require the installation of cooling towers at Diablo Canyon, the Utility could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon, may need to procure substitute power, and may incur a material charge. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

***Hazardous Waste Compliance and Remediation***

The Utility's facilities are subject to the requirements issued by the EPA under the federal Resource Conservation and Recovery Act ("RCRA") and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), as well as other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the

environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site, and in some cases corporate successors to the operators or arrangers. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources, and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility generates waste that falls within CERCLA's definition of hazardous substances and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility has a comprehensive program in place to comply with federal, state, and local laws and regulations related to hazardous materials and hazardous waste compliance, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the California Department of Toxic Substances Control ("DTSC"), several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant ("MGP") sites; current and former power plant sites; former gas gathering and gas storage sites; sites where natural gas compressor stations are located; current and former substations, service centers, and general construction yard sites; and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. For more information about environmental remediation liabilities, see the sections within MD&A entitled "Environmental Matters," "Critical Accounting Polices," and Note 15: Commitments and Contingencies−Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

*Generation Facilities*

Operations at the Utility's current and former generation facilities may have resulted in contaminated soil or groundwater. Although the Utility sold most of its geothermal and fossil fuel-fired plants, in many cases the Utility retained pre-closing environmental liability under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies. Fossil fuel-fired Units 1 and 2 of the Utility's Humboldt Bay power plant shut down in September 2010, and are now in the decommissioning process along with the nuclear Unit 3, which was shut down in 1976. The Utility has entered into a voluntary cleanup agreement with the DTSC and is currently completing a soil and groundwater investigation to determine what soil and groundwater remediation may be necessary.

*Former Manufactured Gas Plant Sites*

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain retired MGP sites. During their operation, from the mid-1800s through the early 1900s, MGPs produced lampblack and coal tar residues. The residues from these operations, which may remain at some sites, contain chemical compounds that now are classified as hazardous. The Utility has been coordinating with environmental agencies and third-party owners to evaluate and take appropriate action to mitigate any potential environmental concerns at 41 MGP sites that the Utility owned or operated in the past. Of these sites owned or operated by the Utility, 40 sites have been or are in the process of being investigated and/or remediated, and the Utility is developing a strategy to investigate and remediate the last site. The Utility spent approximately $51 million in 2012 on these sites.

*Third-Party Owned Disposal Sites*

Under environmental laws, such as CERCLA, the Utility has been or may be required to take remedial action at third-party sites used for the disposal of waste from the Utility's facilities, or to pay for associated clean-up

costs or natural resource damages.  The Utility is currently aware of two such sites where investigation or clean-up activities are currently underway.  At the Geothermal Incorporated site in Lake County, California, the Utility substantially completed closure of the disposal facility, which was abandoned by its operator.  The Utility was the major responsible party and led the remediation effort on behalf of the responsible parties.  For the Casmalia disposal facility near Santa Maria, California, the Utility and several parties that sent waste to the site have entered into a court-approved agreement with the EPA that requires the Utility and the other parties to perform certain site investigation and remediation measures.

*Natural Gas Compressor Stations*

Groundwater at the Utility’s Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility’s past operating practices.  The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.  The Utility has incurred significant environmental liabilities associated with these sites.  For more information about the Utility’s remediation and abatement efforts and related liabilities, see Note 15: Commitments and Contingencies−Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

*Recovery of Environmental Remediation Costs*

The CPUC has authorized the Utility to recover most of its environmental remediation costs through various ratemaking mechanisms, subject to exclusions for certain sites, such as the Hinkley natural gas compressor site, and subject to limitations for certain liabilities such as amounts associated with fossil fuel-fired generation facilities formerly owned by the Utility.  For more information, see Note 15: Commitments and Contingencies−Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report which information is incorporated herein by reference.

***Nuclear Fuel Disposal***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities’ spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities.  The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility’s two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay Unit 3.  As a result, the Utility constructed an interim dry cask storage facility to store spent fuel at Diablo Canyon through at least 2024, and a separate facility at Humboldt Bay.  The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

On September 5, 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010.  For more information, see Note 15: Commitments and Contingencies−Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.  Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

***Nuclear Decommissioning***

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3.  Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility files an application with the CPUC every three years requesting approval of the Utility’s estimated decommissioning costs and authorization to recover the estimated costs through rates.  Nuclear decommissioning charges collected through rates are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit.   (See the discussion of the 2012 Nuclear Decommissioning Cost Triennal Proceeding in Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.)

***Endangered Species***

Many of the Utility's facilities and operations are located in, or pass through, areas that are designated as critical habitats for federal, or state-listed endangered, threatened, or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated at or near the Utility's facilities or operations. The Utility is seeking to secure "habitat conservation plans" to ensure long-term compliance with state and federal endangered species acts. The Utility expects that it will be able to recover costs of complying with state and federal endangered species acts through rates.

**Item 1A.** ***Risk Factors***

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility appears within MD&A under the heading "Risk Factors" in the 2012 Annual Report, which information is incorporated herein by reference.

**Item 1B.** ***Unresolved Staff Comments***

None.

**Item 2.** ***Properties***

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described above under "Electric Utility Operations" and "Natural Gas Utility Operations" which information is incorporated herein by reference. The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In March and September 2012, the Utility entered into 10-year facility lease agreements for 250,000 and 145,000 square feet of office space, respectively, in San Ramon, California. The Utility also recently entered into a lease agreement for a new 12,000 square foot data center located near Sacramento, California. In total, the Utility occupies 10.8 million square feet of real property, including 8.6 million square feet that the Utility owns. Of the 10.8 million square feet of occupied real property, approximately 1.7 million square feet represent the Utility's corporate headquarters located in several Utility-owned buildings in San Francisco, California.

The Utility currently owns approximately 167,000 acres of land, including approximately 140,000 acres of watershed lands. As part of the settlement agreement entered into by PG&E Corporation and the Utility to resolve the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code, the Utility agreed to protect its watershed lands with conservation easements or equivalent protections, and/or donate up to approximately 75,000 acres of its watershed lands to public entities or qualified non-profit conservation organizations. (The Utility will not donate watershed lands that contain the Utility's or a joint licensee's hydroelectric generation facilities or is otherwise used for utility operations, but this land may be encumbered with conservation easements.) The Utility formed a non-profit organization, the Pacific Forest Watershed Lands Stewardship Council ("Council") to oversee the development and implementation of a Land Conservation Plan ("LCP") that will articulate the long-term management objectives for the watershed lands. The Council is governed by an 18-member board of directors, one of whom was appointed by the Utility. The other members represent a range of diverse interests, including the CPUC, California environmental agencies, organizations representing underserved and minority constituencies, agricultural and business interests, and public officials. The Council's goal is to implement the transactions contemplated in the LCP over the next few years, subject to obtaining any required permits and approvals from the FERC, the CPUC, and other governmental agencies.

PG&E Corporation also leases approximately 82,000 square feet of office space from a third party in San Francisco, California, of which 40,000 square feet will expire in 2014 and the remaining in 2022.

**Item 3.** ***Legal Proceedings***

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's liability for legal matters, see Note 15: Commitments and Contingencies−Legal and Regulatory Contingencies, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

***Diablo Canyon Power Plant***

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Regional Water Quality Control Board ("Central Coast Board"). This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

In addition, the California Water Board's policy on once-through cooling and regulations that are expected to be issued by the EPA in July 2013 could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (See "Item 1. Business−Environmental Matters−Water Quality" above.)

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on their Utility's financial condition or results of operations.

***Litigation Related to the San Bruno Accident and Natural Gas Spending***

At December 31, 2012, approximately 140 lawsuits involving third-party claims for personal injury and property damage, including two class action lawsuits, had been filed against PG&E Corporation and the Utility in connection with the San Bruno accident on behalf of approximately 450 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases have been coordinated and assigned to one judge in the San Mateo County Superior Court. The trial of the first group of remaining cases began on January 2, 2013 with pretrial motions and hearings. On January 14, 2013, the court vacated the trial and all pending hearings due to the significant number of cases that have been settled outside of court. The court has urged the parties to settle the remaining cases. As of February 8, 2013, the Utility has entered into settlement agreements to resolve the claims of approximately 140 plaintiffs. It is uncertain whether or when the Utility will be able to resolve the remaining claims through settlement.

Additionally, in October 2010, a purported shareholder derivative lawsuit was filed following the San Bruno accident to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims, relating to the Utility's natural gas business. The case has been coordinated with the other cases in the San Mateo County Superior Court. The judge has ordered that proceedings in the derivative lawsuit be delayed until further order of the court. On February 7, 2013, another purported shareholder derivative lawsuit was filed in U.S. District Court for the Northern District of California to seek recovery on behalf of PG&E Corporation for alleged breaches of fiduciary duty by officers and directors, among other claims.

In addition, on August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. To state their claims, the plaintiffs cited the January 2012 investigative report from the CPUC's Safety and Enforcement Division ("SED") that alleged, from 1996 to 2010, the Utility spent less on capital expenditures and operations and maintenance expense for its natural gas transmission operations than it recovered in rates, by $95 million and $39 million, respectively. The SED recommended that the Utility should use such amounts to fund future gas transmission expenditures and operations. Plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of Section 17200 of the California Business and Professions Code ("Section 17200") and claim that this violation also constitutes a violation of California Public Utilities Code Section 2106 ("Section 2106"), which provides a private right of action for violations of the California constitution or state laws by public utilities. Plaintiffs seek restitution and disgorgement under Section 17200 and compensatory and punitive damages under Section 2106. PG&E Corporation and the Utility contest the allegations. In January 2013, PG&E Corporation and the Utility requested that the court dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. In the alternative, PG&E Corporation and the Utility requested that the court stay the proceeding until the CPUC investigations described above are concluded. The court has set a hearing on the motion for April 26, 2013.

For additional information, see the discussion within MD&A under the heading, "Natural Gas Matters" and in Note 15: Commitments and Contingencies of the Notes to the Consolidated Financial Statements contained in the 2012 Annual Report, which discussions are incorporated herein by reference.

***Pending CPUC Investigations and Potential Enforcement Matters***

The CPUC is conducting three investigations pertaining to the Utility's natural gas operations that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident. In 2012, the SED issued investigative reports in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations and recommending the CPUC impose penalties on the Utility. Evidentiary hearings were held in each of these investigations. The CPUC administrative law judges ("ALJs") who oversee the investigations have adopted a revised procedural schedule, including the dates by which the parties' briefs must be submitted. The ALJs have also permitted the other parties (the City of San Bruno, The Utility Reform Network, and the City and County of San Francisco) to separately address in their opening briefs their allegations against the Utility, if any, in addition to the allegations made by the SED.

The ALJs have ordered the SED and other parties to file single coordinated briefs to address potential monetary penalties and remedies (which could include remedial operational or policy measures) for all three investigations by April 26, 2013. After briefing has been completed, the ALJs will issue one or more presiding officer's decisions listing the violations determined to have been committed, the amount of penalties, and any required remedial actions. Based on the revised procedural schedule, one or more presiding officer's decisions will be issued by July 23, 2013. The decisions would become the final decisions of the CPUC thirty days after issuance unless the Utility or another party filed an appeal, or a CPUC commissioner requested review of the decision, within such time.

California gas corporations are required to provide notice to the CPUC of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and utilities' natural gas operating practices. The CPUC has authorized the SED to issue citations and impose penalties based on self-reported violations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the SED based on the Utility's self-report that it failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has paid the penalty and completed all of the missed leak surveys.) As of December 31, 2012, the Utility has submitted 34 self-reports with the CPUC, plus additional follow-up reports. The SED has not yet taken formal action with respect to the Utility's other self-reports. The SED may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file.

In addition, in July 2012, the Utility reported to the CPUC that it had discovered that its access to some pipelines has been limited by vegetation overgrowth or building structures that encroach upon some of the Utility's gas transmission pipeline rights-of-way. The Utility is undertaking a system-wide effort to identify and remove encroachments from its pipeline rights-of-way over a multi-year period. PG&E Corporation and the Utility are uncertain how this matter will affect the investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced by the CPUC that could result in regulatory orders or the imposition of penalties on the Utility.

The CPUC can impose significant penalties for violations of applicable laws, rules, and orders. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this discretion in determining penalties. The CPUC's delegation of enforcement authority to the SED allows the SED to use these factors in exercising discretion to determine the number of violations, but the SED is required to impose the maximum statutory penalty for each separate violation that the SED finds.

For more information, see discussions within MD&A under the heading, "Natural Gas Matters," and Note 15: Commitments and Contingencies−Legal and Regulatory Contingencies, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which discussions are incorporated herein by reference

***Criminal Investigation***

On June 9, 2011, the Utility was notified that representatives from the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office are conducting an investigation of the San Bruno accident. These representatives have indicated that the Utility is a target of the investigation. The Utility is cooperating with the investigation. PG&E Corporation and the Utility are uncertain whether any criminal charges will be brought against either company or any of their current or former employees. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Utility. See the discussions within MD&A under the heading "Natural Gas Matters – Criminal Investigation," and in Note 15: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which discussions are incorporated herein by reference.

**Item 4. *Mine Safety Disclosures***

Not applicable.

## EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of PG&E Corporation "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934 ("Exchange Act") at February 1, 2013 were as follows.

| Name | Age | Position |
|---|---|---|
| Anthony F. Earley, Jr. | 63 | Chairman of the Board, Chief Executive Officer, and President |
| Kent M. Harvey | 54 | Senior Vice President and Chief Financial Officer |
| Christopher P. Johns | 52 | President, Pacific Gas and Electric Company |
| Hyun Park | 51 | Senior Vice President and General Counsel |
| Greg S. Pruett | 55 | Senior Vice President, Corporate Affairs |
| John R. Simon | 48 | Senior Vice President, Human Resources |

All officers of PG&E Corporation serve at the pleasure of the Board of Directors of PG&E Corporation. During at least the past five years through February 1, 2013, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

| Name | Position | Period Held Office |
|---|---|---|
| Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President | September 13, 2011 to present |
| | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| | Chairman of the Board and Chief Executive Officer, DTE Energy Company | August 1998 to September 30, 2010 |
| Kent M. Harvey | Senior Vice President and Chief Financial Officer | August 1, 2009 to present |
| | Senior Vice President, Financial Services, Pacific Gas and Electric Company | August 1, 2009 to present |
| | Senior Vice President and Chief Risk and Audit Officer | October 1, 2005 to July 31, 2009 |
| Christopher P. Johns | President, Pacific Gas and Electric Company | August 1, 2009 to present |
| | Senior Vice President and Chief Financial Officer | May 1, 2009 to July 31, 2009 |
| | Senior Vice President, Financial Services, Pacific Gas and Electric Company | May 1, 2009 to July 31, 2009 |
| | Senior Vice President, Chief Financial Officer, and Treasurer | October 4, 2005 to April 30, 2009 |
| | Senior Vice President and Treasurer, Pacific Gas and Electric Company | June 1, 2007 to April 30, 2009 |
| Hyun Park | Senior Vice President and General Counsel | November 13, 2006 to present |
| Greg S. Pruett | Senior Vice President, Corporate Affairs | November 1, 2009 to present |
| | Senior Vice President, Corporate Affairs, Pacific Gas and Electric Company | November 1, 2009 to present |
| | Senior Vice President, Corporate Relations | November 1, 2007 to October 31, 2009 |
| | Senior Vice President, Corporate Relations, Pacific Gas and Electric Company | March 1, 2009 to October 31, 2009 |
| John R. Simon | Senior Vice President, Human Resources | April 16, 2007 to present |
| | Senior Vice President, Human Resources, Pacific Gas and Electric Company | April 16, 2007 to present |

The names, ages and positions of the Utility's "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 1, 2013 were as follows:

| Name | Age | Position |
|---|---|---|
| Anthony F. Earley, Jr. | 63 | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation |
| Christopher P. Johns | 52 | President |
| Nickolas Stavropoulos | 54 | Executive Vice President, Gas Operations |
| Geisha J. Williams | 51 | Executive Vice President, Electric Operations |
| Karen A. Austin | 51 | Senior Vice President and Chief Information Officer |
| Desmond A. Bell | 50 | Senior Vice President, Safety and Shared Services |
| Thomas E. Bottorff | 59 | Senior Vice President, Regulatory Affairs |
| Helen A. Burt | 56 | Senior Vice President and Chief Customer Officer |
| John T. Conway | 55 | Senior Vice President, Energy Supply |
| Edward D. Halpin | 51 | Senior Vice President and Chief Nuclear Officer |
| Kent M. Harvey | 54 | Senior Vice President, Financial Services |
| Gregory K. Kiraly | 48 | Senior Vice President, Electric Distribution Operations |
| Hyun Park | 51 | Senior Vice President and General Counsel, PG&E Corporation |
| Greg S. Pruett | 55 | Senior Vice President, Corporate Affairs |
| John R. Simon | 48 | Senior Vice President, Human Resources |
| Jesus Soto, Jr. | 45 | Senior Vice President, Gas Transmission Operations |
| Fong Wan | 51 | Senior Vice President, Energy Procurement |
| Dinyar B. Mistry | 50 | Vice President, Chief Financial Officer, and Controller |

All officers of the Utility serve at the pleasure of the Board of Directors of the Utility. During at least the past five years through February 1, 2013, the executive officers of the Utility had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Position | Period Held Office |
|---|---|---|
| Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation | September 13, 2011 to present |
| | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| | Chairman of the Board and Chief Executive Officer, DTE Energy Company | August 1998 to September 30, 2010 |
| Christopher P. Johns | President | August 1, 2009 to present |
| | Senior Vice President, Financial Services | May 1, 2009 to July 31, 2009 |
| | Senior Vice President and Chief Financial Officer, PG&E Corporation | May 1, 2009 to July 31, 2009 |
| | Senior Vice President and Treasurer | June 1, 2007 to April 30, 2009 |
| | Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation | October 4, 2005 to April 30, 2009 |
| Nickolas Stavropoulos | Executive Vice President, Gas Operations | June 13, 2011 to present |
| | Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid | August 2007 to March 31, 2011 |
| Geisha J. Williams | Executive Vice President, Electric Operations | June 1, 2011 to present |
| | Senior Vice President, Energy Delivery | December 1, 2007 to May 31, 2011 |
| Karen A. Austin | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| | President, Consumer Electronics, Sears Holdings | February 2009 to May 2011 |
| | Executive Vice President, Chief Information Officer, Sears Holdings | March 2005 to January 2009 |
| Desmond A. Bell | Senior Vice President, Safety and Shared Services | January 1, 2012 to present |
| | Senior Vice President, Shared Services and Chief Procurement Officer | October 1, 2008 to December 31, 2011 |
| | Vice President, Shared Services and Chief Procurement Officer | March 1, 2008 to September 30, 2008 |
| | Vice President and Chief of Staff | March 19, 2007 to February 29, 2008 |
| Thomas E. Bottorff | Senior Vice President, Regulatory Affairs | September 1, 2012 to present |
| | Senior Vice President, Regulatory Relations | October 14, 2005 to August 31, 2012 |

| | | |
|---|---|---|
| Helen A. Burt | Senior Vice President and Chief Customer Officer | February 27, 2006 to present |
| John T. Conway | Senior Vice President, Energy Supply | March 1, 2012 to present |
| | Senior Vice President, Energy Supply and Chief Nuclear Officer | April 1, 2009 to February 29, 2012 |
| | Senior Vice President, Generation and Chief Nuclear Officer | October 1, 2008 to March 31, 2009 |
| | Senior Vice President and Chief Nuclear Officer | March 1, 2008 to September 30, 2008 |
| | Site Vice President, Diablo Canyon Power Plant | May 29, 2007 to February 29, 2008 |
| Edward D. Halpin | Senior Vice President and Chief Nuclear Officer | April 2, 2012 to present |
| | President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company | December 2009 to March 2012 |
| | Chief Nuclear Officer, South Texas Project Nuclear Operating Company | October 2008 to November 2009 |
| | Site Vice President, South Texas Project Nuclear Operating Company | June 2006 to September 2008 |
| Kent M. Harvey | Senior Vice President, Financial Services | August 1, 2009 to present |
| | Senior Vice President and Chief Financial Officer, PG&E Corporation | August 1, 2009 to present |
| | Senior Vice President and Chief Risk and Audit Officer, PG&E Corporation | October 1, 2005 to July 31, 2009 |
| Gregory K. Kiraly | Senior Vice President, Electric Distribution Operations | September 18, 2012 to present |
| | Vice President, Electric Distribution Operations | October 1, 2011 to September 17, 2012 |
| | Vice President, SmartMeter Operations | August 23, 2010 to September 30, 2011 |
| | Vice President, Electric Maintenance and Construction | January 1, 2010 to August 22, 2010 |
| | Vice President, Transmission Substations, Maintenance and Construction | January 1, 2009 to December 31, 2009 |
| | Vice President, Maintenance and Construction | April 14, 2008 to December 31, 2008 |
| | Vice President, Distribution Systems Operations, Energy Delivery, Commonwealth Edison Company | June 2007 to April 2008 |
| Hyun Park | Senior Vice President and General Counsel, PG&E Corporation | November 13, 2006 to present |
| Greg S. Pruett | Senior Vice President, Corporate Affairs | November 1, 2009 to present |
| | Senior Vice President, Corporate Affairs, PG&E Corporation | November 1, 2009 to present |
| | Senior Vice President, Corporate Relations | March 1, 2009 to October 31, 2009 |
| | Senior Vice President, Corporate Relations, PG&E Corporation | November 1, 2007 to October 31, 2009 |
| John R. Simon | Senior Vice President, Human Resources | April 16, 2007 to present |
| | Senior Vice President, Human Resources, PG&E Corporation | April 16, 2007 to present |
| Jesus Soto, Jr. | Senior Vice President, Gas Transmission Operations | May 29, 2012 to present |
| | Vice President, Operations Services, El Paso Pipeline Group | May 2007 to May 2012 |
| Fong Wan | Senior Vice President, Energy Procurement | October 1, 2008 to present |
| | Vice President, Energy Procurement | January 9, 2006 to September 30, 2008 |
| Dinyar B. Mistry | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to present |
| | Vice President and Controller, PG&E Corporation | March 8, 2010 to present |
| | Vice President and Controller | March 8, 2010 to September 30, 2011 |
| | Vice President and Chief Risk and Audit Officer | September 16, 2009 to March 7, 2010 |
| | Vice President and Chief Risk and Audit Officer, PG&E Corporation | August 1, 2009 to March 7, 2010 |
| | Vice President, Internal Auditing/Compliance and Ethics, PG&E Corporation | January 1, 2009 to July 31, 2009 |
| | Vice President, Regulation and Rates | September 20, 2007 to December 31, 2008 |

## PART II

**Item 5.** ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

As of February 11, 2013, there were 67,982 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2012 Annual Report, which information is incorporated herein by reference. Shares of common stock of the Utility are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility is set forth in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, Note 6: Common Stock and Share-Based Compensation−Dividends of the Notes to the Consolidated Financial Statements, and within MD&A under the heading "Liquidity and Financial Resources—Dividends," in the 2012 Annual Report, which information is incorporated herein by reference.

***Sales of Unregistered Equity Securities***

During the quarter ended December 31, 2012, PG&E Corporation made equity contributions totaling $170 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2012.

***Issuer Purchases of Equity Securities***

PG&E Corporation common stock:

| Period | Total Number of Shares Purchased | Average Price Per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1 through October 31, 2012 | - | - | - | $ - |
| November 1 through November 30, 2012 | - | - | - | - |
| December 1 through December 31, 2012 | 406 [1] | $39.71 | - | - |
| **Total** | 406 | $39.71 | - | $ - |

[1] Shares of PG&E Corporation common stock tendered to pay stock option exercise price.

During the quarter ended December 31, 2012, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

**Item 6.** ***Selected Financial Data***

Selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2012 Annual Report, which information is incorporated herein by reference.

**Item 7.** ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2012 Annual Report, which discussion is incorporated herein by reference.

**Item 7A.** ***Quantitative and Qualitative Disclosures About Market Risk***

Information responding to Item 7A is set forth within MD&A under the heading "Risk Management Activities," and in Note 10: Derivatives and Note 11: Fair Value Measurements of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

**Item 8.** ***Financial Statements and Supplementary Data***

Information responding to Item 8 is set forth under the following headings for PG&E Corporation: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity" in the 2012 Annual Report and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," and "Reports of Independent Registered Public Accounting Firm" in the 2012 Annual Report, which information is incorporated herein by reference.

**Item 9.** ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***

Not applicable.

**Item 9A.** ***Controls and Procedures***

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2012, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in the 2012 Annual Report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," which information is incorporated by reference and included in Exhibit 13 to this report.

**Item 9B.** ***Other Information***

***2013 PG&E Corporation Short-Term Incentive Plan***

On February 20, 2013, the Compensation Committee of the PG&E Corporation Board of Directors ("Committee") approved the PG&E Corporation 2013 Short-Term Incentive Plan ("STIP") under which officers and employees of PG&E Corporation and the Utility may receive cash awards based on the extent to which specified performance targets are met in each of three areas: safety (both public and employee), customer (which includes operational reliability and the efficient completion of pipeline safety work), and corporate financial performance. The resulting STIP scores for each of these measures will have the following weightings: safety (40%), customer (35%), and corporate financial performance (25%). The Committee also approved the specific performance targets for each of these STIP components.

## PART III

**Item 10.** ***Directors, Executive Officers and Corporate Governance***

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this report. Other information regarding directors is set forth under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act is included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on PG&E Corporation's website *www.pgecorp.com* , and the Utility's website, *www.pge.com* : (1) the codes of conduct and ethics adopted by PG&E Corporation and the Utility applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and the Utility that apply to their respective Chief Executive Officers, Chief Financial Officers, or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within four business days of the waiver.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

During 2012 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial expert" as defined by the SEC is set forth under the headings "Corporate Governance — Board Committee Duties and Composition — Audit Committees" and "Corporate Governance — Board and Director Independence — Committee Membership Requirements" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**Item 11.** ***Executive Compensation***

Information responding to Item 11, for each of PG&E Corporation and the Utility, is set forth under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2012," "Grants of Plan-Based Awards in 2012," "Outstanding Equity Awards at Fiscal Year End - 2012," "Option Exercises and Stock Vested During 2012," "Pension Benefits – 2012," "Non-Qualified Deferred Compensation – 2012," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2012 Director Compensation" in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is hereby incorporated herein by reference.

**Item 12.** ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility, is set forth under the headings "Security Ownership of Management" and "Share Ownership Information - Principal Shareholders" in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

*Equity Compensation Plan Information*

The following table provides information as of December 31, 2012 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a) ) |
|---|---|---|---|
| Equity compensation plans approved by shareholders | 5,758,820[(1)] | $ 30.05 | 4,548,119[(2)] |
| Equity compensation plans not approved by shareholders | - | - | - |
| Total equity compensation plans | 5,758,820[(1)] | $ 30.05 | 4,548,119[(2)] |

(1) Includes 45,597 phantom stock units, 2,101,484 restricted stock units and 3,088,896 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For a description of these performance shares, see Note 6: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which description is incorporated herein by reference. For performance shares, amounts reflected in this table assume payout in shares at 200% of target. The actual number of shares issued can range from 0% to 200% of target depending on achievement of total shareholder return objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) Represents the total number of shares available for issuance under the PG&E Corporation Long-Term Incentive Program (“LTIP”) and the PG&E Corporation 2006 Long-Term Incentive Plan (“2006 LTIP”) as of December 31, 2012. Outstanding stock-based awards granted under the LTIP include stock options, restricted stock, and phantom stock. The LTIP expired on December 31, 2005. The 2006 LTIP, which became effective on January 1, 2006, authorizes up to 12 million shares to be issued pursuant to awards granted under the 2006 LTIP. Outstanding stock-based awards granted under the 2006 LTIP include stock options, restricted stock, restricted stock units, phantom stock and performance shares. For a description of the 2006 LTIP, see Note 6: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which description is incorporated herein by reference.

**Item 13.** ***Certain Relationships and Related Transactions, and Director Independence***

Information responding to Item 13, for each of PG&E Corporation and the Utility, is included under the headings Related Party Transactions and “Information Regarding the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company –Board and Director Independence” in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**Item 14.** ***Principal Accountant Fees and Services***

Information responding to Item 14, for each of PG&E Corporation and the Utility, is set forth under the heading “Information Regarding the Independent Registered Public Accounting Firm for PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**PART IV**

**Item 15.** ***Exhibits and Financial Statement Schedules***

**(a) The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are contained in the 2012 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2012, 2011, and 2010 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2012, 2011, and 2010 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2012 and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011, and 2010 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2012, 2011, and 2010 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2012, 2011, and 2010 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules and report of independent registered public accounting firm are filed as part of this report:

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2012 and 2011 and for the Years Ended December 31, 2012, 2011, and 2010.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2012, 2011, and 2010.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

3. Exhibits required by Item 601 of Regulation S-K

| **Exhibit Number** | **Exhibit Description** |
|---|---|
| 2.1 | Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1) |
| 2.2 | Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2) |
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |

| Exhibit Number | Exhibit Description |
|---|---|
| 3.3 | Bylaws of PG&E Corporation amended as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of June 20, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 3) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility's issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility's issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility's issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility's issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |

| Exhibit Number | Exhibit Description |
|---|---|
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Fifteenth Supplemental Indenture dated as of November 22, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 20, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 22, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1) |
| 4.19 | First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2) |
| 10.1 | Credit Agreement, dated May 31, 2011, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.3 | Credit Agreement, dated May 31, 2011, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.2) |
| 10.4 | Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank |
| 10.5 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.6 | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.7 | Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9) |
| 10.8* | Restricted Stock Unit Agreement between C. Lee Cox and PG&E Corporation dated May 12, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.9* | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.10* | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.11* | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.12* | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.13* | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.14* | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.15* | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5) |
| 10.16* | Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.17* | Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18) |
| 10.18* | Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 |
| 10.19* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |
| 10.20* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.21* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.22* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.23* | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.24* | PG&E Corporation 2005 Supplemental Retirement Savings Plan effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009 and as further amended with respect to investment options effective as of July 13, 2009 and as of August 1, 2011) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.11) |
| 10.25 * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.26* | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.27 * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 |
| 10.28* | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.31) |
| 10.29 * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.30* | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.31 * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 |
| 10.32* | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, effective January 1, 2013 |
| 10.33 * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30) |
| 10.34 * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.35 * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.36* | Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 |
| 10.37* | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 |
| 10.38* | Resolution of the PG&E Corporation Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.31) |
| 10.39 * | Resolution of the Pacific Gas and Electric Company Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2010 (File No. 1-12348), Exhibit 10.32) |
| 10.40* | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 |
| 10.41 * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective June 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.10) |
| 10.42* | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.43* | Form of Restricted Stock Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.44* | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.45* | Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.46* | Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2) |
| 10.47* | Form of Restricted Stock Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.39) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.48* | Form of Amendment to Restricted Stock Agreements for grants made between January 2005 and March 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.45) |
| 10.49* | Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.50 * | Form of Restricted Stock Unit Agreement for 2011 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.9) |
| 10.51* | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.52* | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.53* | Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.54* | Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.55* | Form of Performance Share Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.3) |
| 10.56* | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.57* | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.58* | PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6) |
| 10.59* | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.60* | PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51) |
| 10.61 * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.62* | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.63 * | PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1) |
| 10.64 * | PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.65* | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.66 * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.67 * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 13 | The following portions of the 2012 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," and "Report of Independent Registered Public Accounting Firm." |
| 21 | Subsidiaries of the Registrant |
| 23 | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | Powers of Attorney |
| 31.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

## SIGNATURES

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2012 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| PG&E CORPORATION (Registrant) | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) |
|---|---|
| ANTHONY F. EARLEY, JR. | CHRISTOPHER P. JOHNS |
| By: Anthony F. Earley, Jr.<br>Chairman of the Board, Chief Executive Officer, and President | By: Christopher P. Johns<br>President |
| Date: February 21, 2013 | Date: February 21, 2013 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| **A. Principal Executive Officers** | | |
| ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation) | February 21, 2013 |
| CHRISTOPHER P. JOHNS<br>Christopher P. Johns | President (Pacific Gas and Electric Company) | February 21, 2013 |
| **B. Principal Financial Officers** | | |
| KENT M. HARVEY<br>Kent M. Harvey | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 21, 2013 |
| DINYAR B. MISTRY<br>Dinyar B. Mistry | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 21, 2013 |
| **C. Principal Accounting Officer** | | |
| DINYAR B. MISTRY<br>Dinyar B. Mistry | Vice President and Controller (PG&E Corporation)<br>Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 21, 2013 |
| **D. Directors** | | |
| David R. Andrews | Director | February 21, 2013 |
| *LEWIS CHEW<br>Lewis Chew | Director | February 21, 2013 |
| *C. LEE COX<br>C. Lee Cox | Director | February 21, 2013 |

| | | |
|---|---|---|
| *ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Director | February 21, 2013 |
| *FRED J. FOWLER<br>Fred J. Fowler | Director | February 21, 2013 |
| *MARYELLEN C. HERRINGER<br>Maryellen C. Herringer | Director | February 21, 2013 |
| *CHRISTOPHER P. JOHNS<br>Christopher P. Johns | Director (Pacific Gas and Electric Company only) | February 21, 2013 |
| *ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 21, 2013 |
| *RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 21, 2013 |
| *FORREST E. MILLER<br>Forrest E. Miller | Director | February 21, 2013 |
| *ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 21, 2013 |
| *BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 21, 2013 |
| *BARRY LAWSON WILLIAMS<br>Barry Lawson Williams | Director | February 21, 2013 |

*By: HYUN PARK
HYUN PARK, Attorney-in-Fact

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and the Company's and the Utility's internal control over financial reporting as of December 31, 2012, and have issued our reports thereon dated February 21, 2013 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to several investigations and enforcement matters pending with the California Public Utilities Commission that may result in material amounts of penalties); such consolidated financial statements and reports are included in your 2012 Annual Report to Shareholders of the Company and the Utility and are incorporated herein by reference. Our audits also included the consolidated financial statement schedules of the Company and Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2013

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**
**(in millions, except per share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Administrative service revenue | $ 43 | $ 44 | $ 53 |
| Operating expenses | (41) | (44) | (55) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (22) | (22) | (35) |
| Other income (expense) | (39) | (17) | 4 |
| Equity in earnings of subsidiaries | 817 | 852 | 1,105 |
| Income before income taxes | 759 | 814 | 1,073 |
| Income tax benefit | 57 | 30 | 26 |
| Net income | $ 816 | $ 844 | $ 1,099 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans (net of income tax of $72, $9, $25 in 2012, 2011, and 2010, respectively) | 108 | (11) | (42) |
| Other (net of income tax of $3 in 2012) | 4 | - | - |
| Total other comprehensive income (loss) | 112 | (11) | (42) |
| Comprehensive Income | $ 928 | $ 833 | $ 1,057 |
| Weighted average common shares outstanding, basic | 424 | 401 | 382 |
| Weighted average common shares outstanding, diluted | 425 | 402 | 392 |
| Net earnings per common share, basic | $ 1.92 | $ 2.10 | $ 2.86 |
| Net earnings per common share, diluted | $ 1.92 | $ 2.10 | $ 2.82 |

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS. In addition, during 2010, PG&E Corporation applied the “if-converted” method to reflect the impact of the Convertible Subordinated Notes to the extent it was dilutive when compared to basic EPS.

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2012** | **2011** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 207 | $ 209 |
| Advances to affiliates | 26 | 18 |
| Income taxes receivable | 33 | 8 |
| Deferred income taxes | - | 4 |
| **Total current assets** | 266 | 239 |
| **Noncurrent Assets** | | |
| Equipment | 1 | 14 |
| Accumulated depreciation | (1) | (14) |
| Net equipment | - | - |
| Investments in subsidiaries | 13,387 | 12,378 |
| Other investments | 102 | 94 |
| Income taxes receivable | 5 | 2 |
| Deferred income taxes | 178 | 143 |
| Other | 1 | 2 |
| **Total noncurrent assets** | 13,673 | 12,619 |
| **Total Assets** | $ 13,939 | $ 12,858 |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 120 | $ - |
| Accounts payable – other | 48 | 21 |
| Income taxes payable | - | 57 |
| Other | 221 | 208 |
| **Total current liabilities** | 389 | 286 |
| **Noncurrent Liabilities** | | |
| Long-term debt | 349 | 349 |
| Other | 127 | 122 |
| **Total noncurrent liabilities** | 476 | 471 |
| **Common Shareholders' Equity** | | |
| Common stock | 8,428 | 7,602 |
| Reinvested earnings | 4,747 | 4,712 |
| Accumulated other comprehensive loss | (101) | (213) |
| **Total common shareholders' equity** | 13,074 | 12,101 |
| **Total Liabilities and Shareholders' Equity** | $ 13,939 | $ 12,858 |

**PG&E CORPORATION**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| **Cash Flows from Operating Activities:** | | | |
| Net income | $ 816 | $ 844 | $ 1,099 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 51 | 36 | 38 |
| Equity in earnings of subsidiaries | (817) | (852) | (1,105) |
| Deferred income taxes and tax credits, net | (31) | (26) | 19 |
| Noncurrent income taxes receivable/payable | (6) | (47) | 34 |
| Current income taxes receivable/payable | (82) | 49 | (1) |
| Other | 20 | (80) | (50) |
| **Net cash provided by (used in) operating activities** | (49) | (76) | 34 |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (1,023) | (759) | (347) |
| Dividends received from subsidiaries [1] | 716 | 716 | 716 |
| Proceeds from tax equity investments | 228 | 129 | 7 |
| Other | - | - | (4) |
| **Net cash provided by (used in) investing activities** | (79) | 86 | 372 |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings under revolving credit facilities | 120 | 150 | 90 |
| Repayments under revolving credit facilities | - | (150) | (90) |
| Common stock issued | 751 | 662 | 303 |
| Common stock dividends paid [2] | (746) | (704) | (662) |
| Other | 1 | 1 | - |
| **Net cash provided by (used in) financing activities** | 126 | (41) | (359) |
| **Net change in cash and cash equivalents** | (2) | (31) | 47 |
| **Cash and cash equivalents at January 1** | 209 | 240 | 193 |
| **Cash and cash equivalents at December 3 1** | $ 207 | $ 209 | $ 240 |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (20) | $ (20) | $ (20) |
| Income taxes, net | (60) | 8 | 36 |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Noncash common stock issuances | $ 22 | $ 24 | $ 265 |
| Common stock dividends declared but not yet paid | 196 | 188 | 183 |

(1) Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries an investing cash flow.

(2) On January 15, April 15, July 15, October 15, 2012, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

On January 15, April 15, July 15, October 15, 2011, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

On January 15, 2010, PG&E Corporation paid a quarterly common stock dividend of $0.42 per share. On April 15, July 15, and October 15, 2010, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

**PG&E Corporation**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2012, 2011, and 2010**
**(in millions)**

| Description | Balance at Beginning of Period | Additions: Charged to Costs and Expenses | Additions: Charged to Other Accounts | Deductions [2] | Balance at End of Period |
|---|---|---|---|---|---|
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2012: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 66 | $ - | $ 60 | $ 87 |
| 2011: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 60 | $ - | $ 60 | $ 81 |
| 2010: | | | | | |
| Allowance for uncollectible accounts [1] | $ 68 | $ 56 | $ - | $ 43 | $ 81 |

(1) Allowance for uncollectible accounts is deducted from "Accounts receivable – Customers."

(2) Deductions consist principally of write-offs, net of collections of receivables previously written off.

**Pacific Gas and Electric Company**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2012, 2011, and 2010**
**(in millions)**

| | | Additions | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions** (2) | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2012: | | | | | |
| Allowance for uncollectible accounts (1) | $ 81 | $ 66 | $ - | $ 60 | $ 87 |
| 2011: | | | | | |
| Allowance for uncollectible accounts (1) | $ 81 | $ 60 | $ - | $ 60 | $ 81 |
| 2010: | | | | | |
| Allowance for uncollectible accounts (1) | $ 68 | $ 56 | $ - | $ 43 | $ 81 |

(1) Allowance for uncollectible accounts is deducted from "Accounts receivable – Customers."

(2) Deductions consist principally of write-offs, net of collections of receivables previously written off.

## EXHIBIT INDEX

| Exhibit Number | Exhibit Description |
|---|---|
| 2.1 | Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1) |
| 2.2 | Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2) |
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of March 1, 2012 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of June 20, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 3) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility’s issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |

| Exhibit Number | Exhibit Description |
|---|---|
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Fifteenth Supplemental Indenture dated as of November 22, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 20, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 22, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1) |

| Exhibit Number | Exhibit Description |
|---|---|
| 4.19 | First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation’s 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation’s Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2) |
| 10.1 | Credit Agreement, dated May 31, 2011, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank |
| 10.3 | Credit Agreement, dated May 31, 2011, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.2) |
| 10.4 | Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank |
| 10.5 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.6 | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation’s and Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.7 | Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation’s and Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9) |
| 10.8* | Restricted Stock Unit Agreement between C. Lee Cox and PG&E Corporation dated May 12, 2011 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.3) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.9* | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.10* | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.11* | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.12* | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.13* | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.14* | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.15* | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5) |
| 10.16* | Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.17* | Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18) |
| 10.18* | Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 |
| 10.19* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |
| 10.20* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.21* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.22* | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.23* | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.24* | PG&E Corporation 2005 Supplemental Retirement Savings Plan effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009 and as further amended with respect to investment options effective as of July 13, 2009 and as of August 1, 2011) (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.11) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.25 * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.26* | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.27 * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 |
| 10.28* | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.31) |
| 10.29 * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.30* | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.31 * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 |
| 10.32* | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, effective January 1, 2013 |
| 10.33 * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30) |
| 10.34 * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.35 * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.36* | Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 |
| 10.37* | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 |
| 10.38* | Resolution of the PG&E Corporation Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.31) |
| 10.39 * | Resolution of the Pacific Gas and Electric Company Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2010 (File No. 1-12348), Exhibit 10.32) |
| 10.40* | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 |
| 10.41 * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective June 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.10) |
| 10.42* | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |

| Exhibit Number | Exhibit Description |
|---|---|
| 10.43* | Form of Restricted Stock Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.44* | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.45* | Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.46* | Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2) |
| 10.47* | Form of Restricted Stock Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.39) |
| 10.48* | Form of Amendment to Restricted Stock Agreements for grants made between January 2005 and March 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.45) |
| 10.49* | Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.50 * | Form of Restricted Stock Unit Agreement for 2011 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.9) |
| 10.51* | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.52* | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.53* | Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.54* | Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.55* | Form of Performance Share Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.3) |
| 10.56* | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.57* | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.58* | PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6) |

| Exhibit Number | Exhibit Descrkiption |
|---|---|
| 10.59* | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.60* | PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51) |
| 10.61 * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.62* | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.63 * | PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1) |
| 10.64 * | PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39) |
| 10.65* | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.66 * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.67 * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 13 | The following portions of the 2012 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: “Selected Financial Data,” “Management's Discussion and Analysis of Financial Condition and Results of Operations,” financial statements of PG&E Corporation entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Equity,” financial statements of Pacific Gas and Electric Company entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity,” “Notes to the Consolidated Financial Statements,” “Quarterly Consolidated Financial Data (Unaudited),” “Management's Report on Internal Control Over Financial Reporting,” and “Report of Independent Registered Public Accounting Firm.” |
| 21 | Subsidiaries of the Registrant |
| 23 | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | Powers of Attorney |

| Exhibit Number | Exhibit Description |
|---|---|
| 31.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.
** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

**AMENDMENT NO. 1 TO CREDIT AGREEMENT**

This AMENDMENT NO. 1 TO CREDIT AGREEMENT (this " Amendment "), dated as of December 24, 2012, is entered into by and among (1) PG&E CORPORATION, a California corporation (the " Borrower "); (2) the Required Lenders (as defined in the Credit Agreement referred to below); and (3) BANK OF AMERICA, N.A., as Administrative Agent, with respect to the following:

A. The Borrower, the Administrative Agent and the Lenders have previously entered into that certain Credit Agreement dated as of May 31, 2011 (the " Existing Credit Agreement " and as the same may be further amended, restated, supplemented or otherwise modified and in effect from time to time, including, but not limited to, by this Amendment, the " Credit Agreement "). Capitalized terms are used in this Amendment as defined in the Credit Agreement, unless otherwise defined herein.

B. The Borrower, the Administrative Agent and the Required Lenders desire to make certain amendments to the Existing Credit Agreement as set forth below on the terms and subject to the conditions set forth in this Amendment.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. **Effectiveness** . The effectiveness of the provisions of Section 2 of this Amendment is subject to the satisfaction of the conditions further described in Section 3 of this Amendment.

2. **Amendment to Section 8** . On the terms and subject to the conditions of this Amendment, Section 8 of the Existing Credit Agreement is hereby amended by deleting clause (h) in its entirety and replacing it with the following:

"(h) one or more judgments or decrees shall be entered against the Borrower or any of its Significant Subsidiaries by a court of competent jurisdiction involving in the aggregate a liability (not paid or, subject to customary deductibles, fully covered by insurance as to which the relevant insurance company has not denied coverage) of $100,000,000 or more, and all such judgments or decrees shall not have been vacated, discharged, stayed or bonded pending appeal within 30 days from the entry thereof unless, in the case of a discharge, such judgment or decree is due at a later date in one or more payments and the Borrower or such Subsidiary satisfies the obligation to make such payment or payments on or prior to the date such payment or payments become due in accordance with such judgment or decree; or."

3. **Conditions Precedent to the Effectiveness of this Amendment** . The effectiveness of the provisions of Section 2 of this Amendment is conditioned upon, and such provisions shall not be effective until, satisfaction of the following conditions (the first date on which all of the following conditions have been satisfied being referred to herein as the " Amendment Effective Date "):

(a) The Administrative Agent shall have received, on behalf of the Lenders, this Amendment, duly executed and delivered by the Borrower, the Administrative Agent and the Required Lenders.

(b) The representations and warranties set forth in Section 4 of this Amendment shall be true and correct as of the Amendment Effective Date.

(c) No Default or Event of Default shall have occurred and be continuing on the date of the Amendment Effective Date or after giving effect to this Amendment.

4. **Representations and Warranties**. In order to induce the Administrative Agent and the Lenders to enter into this Amendment and to amend the Existing Credit Agreement in the manner provided in this Amendment, the Borrower represents and warrants to the Administrative Agent and each Lender that (a) each of the representations and warranties made by the Borrower in the Credit Agreement (i) that does not contain a materiality qualification (other than the representations and warranties set forth in Section 4.2, 4.6(b) and 4.13) shall be true and correct in all material respects on and as of the date of the Amendment Effective Date as if made on and as of such date, and (ii) that contains a materiality qualification (other than the representations and warranties set forth in Sections 4.2, 4.6(b) and 4.13) shall be true and correct on and as of the Amendment Effective Date (or, to the extent such representations and warranties specifically relate to an earlier date, that such representations and warranties were true and correct in all material respects, or true and correct, as the case may be, as of such earlier date); (b) the Borrower has the corporate power and corporate authority to make and deliver this Amendment and to perform the Existing Credit Agreement as amended by this Amendment; (c) the Borrower has taken all necessary corporate action to authorize the execution and delivery of this Amendment and the performance of the Existing Credit Agreement as amended by this Amendment; (d) this Amendment has been duly executed and delivered by the Borrower and constitutes a legal, valid and binding obligation of the Borrower, enforceable against the Borrower in accordance with its terms, except as enforceability may be limited by (x) applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the enforcement of creditors' rights generally, laws of general application related to the enforceability of securities secured by real estate and by general equitable principles (whether enforcement is sought by proceedings in equity or at law) and (y) applicable regulatory requirements (including the approval of the CPUC) prior to foreclosure under the Indenture; and (e) t he execution and delivery by the Borrower of this Amendment and the performance by the Borrower of this Amendment do not (x) violate in any material respect any Requirement of Law or any Contractual Obligation of the Borrower or any of its Significant Subsidiaries; or (y) result in, or require, the creation or imposition of any Lien on any of their respective properties or revenues pursuant to any Requirement of Law or any such Contractual Obligation (other than the Liens created by the Indenture).

5. **Miscellaneous**.

(a) Reference to and Effect on the Existing Credit Agreement and the other Loan Documents.

(i) Except as specifically amended by this Amendment, the Existing Credit Agreement and the other Loan Documents shall remain in full force and effect and are hereby ratified and confirmed by the Borrower in all respects.

(ii) The execution and delivery of this Amendment and performance of the Credit Agreement shall not, except as expressly provided herein, constitute a waiver of any provision of, or operate as a waiver of any right, power or remedy of the Administrative Agent or the Lenders under, the Existing Credit Agreement or any of the other Loan Documents.

(iii) Upon the conditions precedent set forth herein being satisfied, this Amendment shall be construed as one with the Existing Credit Agreement, and the Existing Credit Agreement shall, where the context requires, be read and construed throughout so as to incorporate this Amendment.

(iv) If there is any conflict between the terms and provisions of this Amendment and the terms and provisions of the Credit Agreement or any other Loan Document, the terms and provisions of this Amendment shall govern.

(b) Counterparts. This Amendment may be executed by one or more of the parties to this Amendment on any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Amendment by facsimile transmission (or by email of a PDF or similar electronic image file) shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this Amendment signed by all of the parties shall be lodged with the Borrower and the Administrative Agent.

(c) Governing Law. This Amendment and the rights and obligations of the parties under this Amendment shall be governed by, and construed and interpreted in accordance with, the law of the State of New York.

6. **Loan Documents**. This Amendment is a Loan Document as defined in the Credit Agreement, and the provisions of the Credit Agreement generally applicable to Loan Documents are applicable hereto and incorporated herein by this reference.

[This Space Intentionally Left Blank]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed as of the date first above written.

PG&E CORPORATION

By: NICHOLAS M. BIJUR
Name: Nicholas M. Bijur
Title: Vice President and Treasurer

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

BANK OF AMERICA, N.A.
as Administrative Agent, an Issuing Lender and as a Lender

By: PATRICK MARTIN
Name: Patrick Martin
Title: Director

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

CITIBANK, N.A.
as Co-Syndication Agent, an Issuing Lender and as a Lender

By: MAUREEN P. MARONEY
Name: Maureen P. Maroney
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

JPMORGAN CHASE BANK, N.A.,
as Co-Syndication Agent, an Issuing Lender and as a Lender

By: JUAN JAVELLANA
Name: Juan Javellana
Title: Executive Director

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

THE ROYAL BANK OF SCOTLAND PLC,
as Co-Documentation Agent, an Issuing Lender and as a Lender

By: EMILY FREEDMAN
Name: Emily Freedman
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

LOSANGELES 985499 (2K)

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Co-Documentation Agent, an Issuing Lender and as a Lender

By: GABRIELA RAMIREZ
Name: Gabriela Ramirez
Title: Assistant Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

LOSANGELES 985499 (2K)

BANCO BILBAO VIZCAYA ARGENTARIA,
S.A. NEW YORK BRANCH,
as a Lender

By: NIETZSCHE RODRICKS
Name: Nietzsche Rodricks
Title: Executive Director

By: MICHAEL OKA
Name: Michael Oka
Title: Executive Director

THE BANK OF NEW YORK MELLON,
as a Lender

By: MARK W. ROGERS
Name: Mark W. Rogers
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

Barclays Bank PLC,
as a Lender

By: MAY HUANG
Name: May Huang
Title: Assistant Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

BNP PARIBAS,
as a Lender

By: DENIS O'MEARA
Name: Denis O'Meara
Title: Managing Director

By: FRANCIS J. DELANEY
Name: Francis J. Delaney
Title: Managing Director

DEUTSCHE BANK AG NEW YORK BRANCH,
as a Lender

By: MING K. CHU
Ming K Chu
Vice President

By: HEIDI SANDQUIST
Heidi Sandquist
Director

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

GOLDMAN SACHS BANK USA
as a Lender

By: MICHELLE LATZONI
Name: Michelle Latzoni
Title: Authorized Signatory

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

MIZUHO CORPORATE BANK, LTD.,
as a Lender

By: LEON MO
Name: Leon Mo
Title: Authorized Signatory

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

Morgan Stanley Bank, N.A.
as a Lender

By: JOHN DURLAND
Name: John Durland
Title: Authorized Signatory

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

Royal Bank of Canada,
as a Lender

By: THOMAS CASEY
Name: Thomas Casey
Title: Authorized Signatory

UBS LOAN FINANCE LLC
as a Lender

By: LANA GIFAS
Name: Lana Gifas
Title: Director

By: JOSELIN FERNANDES
Name: Joselin Fernandes
Title: Associate Director

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

Union Bank, N.A.
as a Lender

By: DENNIS BLANK
Name: Dennis Blank
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – PG&E Corporation]

**AMENDMENT NO. 1 TO CREDIT AGREEMENT**

This AMENDMENT NO. 1 TO CREDIT AGREEMENT (this " Amendment "), dated as of December 24, 2012, is entered into by and among (1) PACIFIC GAS AND ELECTRIC COMPANY, a California corporation (the " Borrower "); (2) the Required Lenders (as defined in the Credit Agreement referred to below); and (3) CITIBANK, N.A., as Administrative Agent, with respect to the following:

A. The Borrower, the Administrative Agent and the Lenders have previously entered into that certain Credit Agreement dated as of May 31, 2011 (the " Existing Credit Agreement " and as the same may be further amended, restated, supplemented or otherwise modified and in effect from time to time, including, but not limited to, by this Amendment, the " Credit Agreement "). Capitalized terms are used in this Amendment as defined in the Credit Agreement, unless otherwise defined herein.

B. The Borrower, the Administrative Agent and the Required Lenders desire to make certain amendments to the Existing Credit Agreement as set forth below on the terms and subject to the conditions set forth in this Amendment.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. **Effectiveness** . The effectiveness of the provisions of Section 2 of this Amendment is subject to the satisfaction of the conditions further described in Section 3 of this Amendment.

2. **Amendment to Section 8** . On the terms and subject to the conditions of this Amendment, Section 8 of the Existing Credit Agreement is hereby amended by deleting clause (h) in its entirety and replacing it with the following:

"(h) one or more judgments or decrees shall be entered against the Borrower or any of its Significant Subsidiaries by a court of competent jurisdiction involving in the aggregate a liability (not paid or, subject to customary deductibles, fully covered by insurance as to which the relevant insurance company has not denied coverage) of $100,000,000 or more, and all such judgments or decrees shall not have been vacated, discharged, stayed or bonded pending appeal within 30 days from the entry thereof unless, in the case of a discharge, such judgment or decree is due at a later date in one or more payments and the Borrower or such Subsidiary satisfies the obligation to make such payment or payments on or prior to the date such payment or payments become due in accordance with such judgment or decree; or."

3. **Conditions Precedent to the Effectiveness of this Amendment** . The effectiveness of the provisions of Section 2 of this Amendment is conditioned upon, and such provisions shall not be effective until, satisfaction of the following conditions (the first date on which all of the following conditions have been satisfied being referred to herein as the " Amendment Effective Date "):

(a) The Administrative Agent shall have received, on behalf of the Lenders, this Amendment, duly executed and delivered by the Borrower, the Administrative Agent and the Required Lenders.

(b) The representations and warranties set forth in Section 4 of this Amendment shall be true and correct as of the Amendment Effective Date.

(c) No Default or Event of Default shall have occurred and be continuing on the date of the Amendment Effective Date or after giving effect to this Amendment.

4. **Representations and Warranties** . In order to induce the Administrative Agent and the Lenders to enter into this Amendment and to amend the Existing Credit Agreement in the manner provided in this Amendment, the Borrower represents and warrants to the Administrative Agent and each Lender that (a) each of the representations and warranties made by the Borrower in the Credit Agreement (i) that does not contain a materiality qualification (other than the representations and warranties set forth in Section 4.2, 4.6(b) and 4.13) shall be true and correct in all material respects on and as of the date of the Amendment Effective Date as if made on and as of such date, and (ii) that contains a materiality qualification (other than the representations and warranties set forth in Sections 4.2, 4.6(b) and 4.13) shall be true and correct on and as of the Amendment Effective Date (or, to the extent such representations and warranties specifically relate to an earlier date, that such representations and warranties were true and correct in all material respects, or true and correct, as the case may be, as of such earlier date); (b) the Borrower has the corporate power and corporate authority to make and deliver this Amendment and to perform the Existing Credit Agreement as amended by this Amendment; (c) the Borrower has taken all necessary corporate action to authorize the execution and delivery of this Amendment and the performance of the Existing Credit Agreement as amended by this Amendment; (d) this Amendment has been duly executed and delivered by the Borrower and constitutes a legal, valid and binding obligation of the Borrower, enforceable against the Borrower in accordance with its terms, except as enforceability may be limited by (x) applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the enforcement of creditors' rights generally, laws of general application related to the enforceability of securities secured by real estate and by general equitable principles (whether enforcement is sought by proceedings in equity or at law) and (y) applicable regulatory requirements (including the approval of the CPUC) prior to foreclosure under the Indenture; and (e) t he execution and delivery by the Borrower of this Amendment and the performance by the Borrower of this Amendment do not (x) violate in any material respect any Requirement of Law or any Contractual Obligation of the Borrower or any of its Significant Subsidiaries; or (y) result in, or require, the creation or imposition of any Lien on any of their respective properties or revenues pursuant to any Requirement of Law or any such Contractual Obligation (other than the Liens created by the Indenture).

5. **Miscellaneous**.

(a) Reference to and Effect on the Existing Credit Agreement and the other Loan Documents.

(i) Except as specifically amended by this Amendment, the Existing Credit Agreement and the other Loan Documents shall remain in full force and effect and are hereby ratified and confirmed by the Borrower in all respects.

(ii) The execution and delivery of this Amendment and performance of the Credit Agreement shall not, except as expressly provided herein, constitute a waiver of any provision of, or operate as a waiver of any right, power or remedy of the Administrative Agent or the Lenders under, the Existing Credit Agreement or any of the other Loan Documents.

(iii) Upon the conditions precedent set forth herein being satisfied, this Amendment shall be construed as one with the Existing Credit Agreement, and the Existing Credit Agreement shall, where the context requires, be read and construed throughout so as to incorporate this Amendment.

(iv) If there is any conflict between the terms and provisions of this Amendment and the terms and provisions of the Credit Agreement or any other Loan Document, the terms and provisions of this Amendment shall govern.

(b) Counterparts. This Amendment may be executed by one or more of the parties to this Amendment on any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Amendment by facsimile transmission (or by email of a PDF or similar electronic image file) shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this Amendment signed by all of the parties shall be lodged with the Borrower and the Administrative Agent.

(c) Governing Law. This Amendment and the rights and obligations of the parties under this Amendment shall be governed by, and construed and interpreted in accordance with, the law of the State of New York.

6. **Loan Documents**. This Amendment is a Loan Document as defined in the Credit Agreement, and the provisions of the Credit Agreement generally applicable to Loan Documents are applicable hereto and incorporated herein by this reference.

[This Space Intentionally Left Blank]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed as of the date first above written.

PACIFIC GAS AND ELECTRIC COMPANY

By: NICHOLAS M. BIJUR
Name: Nicholas M. Bijur
Title: Vice President and Treasurer

CITIBANK, N.A.
as Administrative Agent, an Issuing Lender and as a Lender

By: MAUREEN P. MARONEY
Name: Maureen P. Maroney
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

BANK OF AMERICA, N.A.
as Administrative Agent, an Issuing Lender and as a Lender

By: PATRICK MARTIN
Name: Patrick Martin
Title: Director

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

JPMORGAN CHASE BANK, N.A.,
as Co-Syndication Agent, an Issuing Lender and as a Lender

By: JUAN JAVELLANA
Name: Juan Javellana
Title: Executive Director

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

LOSANGELES 985498 (2K)

THE ROYAL BANK OF SCOTLAND PLC,
as Co-Documentation Agent, an Issuing Lender and as a Lender

By: EMILY FREEDMAN
Name: Emily Freedman
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

BANCO BILBAO VIZCAYA ARGENTARIA,
S.A. NEW YORK BRANCH,
as a Lender

By: NIETZSCHE RODRICKS
Name: Nietzsche Rodricks
Title: Executive Director

By: EDUARDO CUTRIM
Name: Eduardo Cutrim
Title: Executive Director

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

THE BANK OF NEW YORK MELLON,
as a Lender

By: MARK W. ROGERS
Name: Mark W. Rogers
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.,
as a Lender

By: ALAN REITER
Name: Alan Reiter
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]
LOSANGELES 985498 (2K)

Barclays Bank PLC,
as a Lender

By: MAY HUANG
Name: May Huang
Title: Assistant Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]
LOSANGELES 985498 (2K)

BNP PARIBAS,
as a Lender

By: DENIS O'MEARA
Name: Denis O'Meara
Title: Managing Director

By: FRANCIS J. DELANEY
Name: Francis J. Delaney
Title: Managing Director

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

DEUTSCHE BANK AG NEW YORK BRANCH,
as a Lender

By: MING K. CHU
Ming K Chu
Vice President

By: HEIDI SANDQUIST
Heidi Sandquist
Director

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

GOLDMAN SACHS BANK USA,
as a Lender

By: MICHELLE LATZONI
Name: Michelle Latzoni
Title: Authorized Signatory

MIZUHO CORPORATE BANK, LTD.,
as a Lender

By: LEON MO
Name: Leon Mo
Title: Authorized Signatory

Morgan Stanley Bank, N.A.,
as a Lender

By: JOHN DURLAND
Name: John Durland
Title: Authorized Signatory

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

Royal Bank of Canada,
as a Lender

By: THOMAS CASEY
Name: Thomas Casey
Title: Authorized Signatory

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]
LOSANGELES 985498 (2K)

UBS LOAN FINANCE LLC,
as a Lender

By: LANA GIFAS
Name: Lana Gifas
Title: Director

By: JOSELIN FERNANDES
Name: Joselin Fernandes
Title: Associate Director

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

LOSANGELES 985498 (2K)

Union Bank, N.A.
as a Lender

By: DENNIS BLANK
Name: Dennis Blank
Title: Vice President

[Signature Page to Amendment No. 1 to Credit Agreement – Pacific Gas and Electric Company]

Exhibit 10.18

PG&E Corporation.

**Peter A. Darbee**
Chairman of the Board
Chief Executive Officer and President

1 Market, Spear Tower
Suite 2400
San Francisco CA 94105

415.267.7118
Fax: 415.267.7252

March 9, 2007

Mr. John Simon
5403 South Chester Court
Greenwood Village, CO 80111

Dear Hyun:

On behalf of PG&E Corporation, I am pleased to extend an invitation to you to join our organization as Senior Vice President, Human Resources, reporting to me.

Your initial total compensation package will consist of the following:

1. An annual base salary of $325,000 ($27,083.33/month) subject to possible increases through our annual salary review plan.

2. A one-time bonus of $100,000 payable within 60 days of your date of hire, subject to normal tax withholdings. Should you leave the company or should your employment be terminated for cause within two years of your date of hire, a prorated amount of this bonus must be refunded to the company.

3. A target incentive of $162,500 (50% of your base salary) in an annual short-term incentive plan under which your actual incentive dollars may range from zero to $325,000 based on performance relative to established goals. This incentive will be prorated for the number of months worked from your date of hire and will be payable in 2008.

4. Participation in the PG&E Corporation Long-Term Incentive Plan (LTIP) as a band 3 officer. Grants under the LTIP are currently split equally between restricted stock and performance shares, and are generally made annually on the first business day of the year. Your initial LTIP grant will be made on your date of hire, and will have an estimated value of $300,000. This estimated value is used only for the purpose of determining the number of shares for your grant, which will be based on the closing price of PG&E Corporation common stock (PCG) on your date of hire. The ultimate value that you realize from these grants will depend upon your employment status and the performance of PG&E Corporation common stock.

5. A one-time supplement LTIP grant with an estimated current value of $200,000. This grant will be apportioned and made in the same manner as the grant described in item 5.

6. Participation in the PG&E Corporation Supplemental Executive Retirement Plan (SERP). The basic benefit payable from the SERP at retirement is a monthly annuity equal to the product of 1.7% x [average of the three highest years' combination of salary and annual incentive for the last ten years of service] x years of credited service x 1/12 less any amounts paid or payable from the Pacific Gas and Electric Company Retirement Plan (RP).

7. Conditioned upon meeting plan requirements, you will also be eligible for post-retirement life insurance and post-retirement medical benefits upon retirement under the RP.

8. Participation in the PG&E Corporation Retirement Savings Plan (RSP), a 401(k) defined contribution plan. You will be eligible to contribute as much as 20% of your salary on either a pre-tax or after-tax basis, subject to legal limits. After your first year of service, we will match contributions you make, up to 3% of your salary, at 75 cents on each dollar contributed for the second and third years of your employment. Thereafter, we will match contributions up to 6% of your salary at 75 cents on each dollar contributed.

9. Participation in the PG&E Corporation Supplemental Retirement Savings Plan (SRSP), a non-qualified deferred compensation plan. You may elect to defer payment of some of your compensation on a pre-tax basis. We will provide you with the full matching contributions that cannot be provided through the RSP due to legal limitations imposed on highly compensated employees.

10. As a result of your officer level (officer band 3), you will become an eligible participant under Executive Stock Ownership Program effective January 1, 2008. As an ancillary benefit to that program, you will also be eligible to receive financial counseling from The AYCO Company at a subsidized rate to assist you in your understanding of our compensation and benefits programs and how those programs can help you to achieve financial security.

11. Participation in a cafeteria-style benefits program that permits you to select coverage tailored to your personal needs and circumstances. The benefits you elect will be effective the first of the month following the date of your hire.

12. PG&E Corporation also offers a paid-time off (PTO) program. You will be eligible for 200 (25 days) per year. You will accrue PTO at rate of approximately 17 hours per month, provided that you work full-time for the month. In addition, PG&E Corporation recognizes ten paid company holidays annually and provides three floating holidays immediately upon hire and at the beginning of each year.

13. An annual perquisite allowance of $20,000 to be used in lieu of individual authorizations for cars and memberships in clubs and civic organizations.

14. A comprehensive executive relocation assistance package, including: (1) the reimbursement of closing costs on the sale of your current residence, contingent upon using a PG&E-designated relocation company and purchasing a new residence, (2) the move of your household goods, including 60 days of storage and the movement of the goods out of storage, and (3) a lump sum payment of $10,000 payable within 60 days of your date of employment. In addition, the package will include financial assistance in the form of a monthly mortgage subsidy of $3,000 (applicable to interest only) for a period of 36 months. This subsidy is contingent upon the following: (1) your purchase of a principal residence (within 50 miles of your work location) within one year of your date of hire, (2) your satisfying typical mortgage qualification criteria, and (3) use of a company-designated lender. Should you have any questions regarding the relocation package, please contact Denise Nicco, Director of Relocation at (415) 973-3814.

PG&E Corporation.

Mr. Simon
March 9, 2007
Page 3

This offer is contingent upon your passing a comprehensive background verification including a credit check and security clearance assessment, and a standard drug analysis test. We will also need to verify your eligibility to work in the United States based on applicable immigration laws. In addition, your election as an officer of PG&E Corporation is subject to approval by the Board of Directors of PG&E Corporation, and elements of your compensation are subject to approval by the Nominating, Compensation, and Governance Committee of the Board of Directors of PG&E Corporation.

I look forward to your joining our team and believe you will make a strong contribution to the achievement of our being the leading utility in the United States. I would appreciate receiving your written acceptance of this offer as soon as possible. Please call me at any time if you have questions.

Sincerely,

/s/ PETER A. DARBEE

PETER A. DARBEE

Attachment

This is to confirm my acceptance of PG&E Corporation's offer as Senior Vice President, Human Resources as outlined above.

JOHN R. SIMON

(Signature and Date)

# 2013 OFFICER SHORT-TERM INCENTIVE PLAN

On February 20, 2013, the Compensation Committee of the PG&E Corporation Board of Directors ("Committee") approved the structure of the 2013 Short-Term Incentive Plan ("STIP"), as well as the weighting and the specific performance targets for each component of the 2013 STIP. Officers of PG&E Corporation and Pacific Gas and Electric Company ("Utility") (together, the "Companies") are eligible to receive cash incentives under the STIP based on the extent to which the adopted 2013 performance targets are met. Target cash awards under the STIP may range from 40 percent to 100 percent of base salary depending on officer level. STIP company performance may range from a score of 0 to 2.0. The Committee may apply an individual performance modifier from 0 percent to 150 percent to individual officer awards. The Committee will retain complete discretion to determine and pay all STIP awards to officers and non-officer employees. This includes discretion to reduce the final score on any and all measures downward to zero.

The Committee approved the 2013 performance targets for each of the three categories set forth in the table below.

The corporate financial performance target, with a weighting of 25%, is based on PG&E Corporation's budgeted earnings from operations that were previously approved by the Board of Directors, consistent with the basis for reporting and guidance to the financial community. As with previous earnings performance scales, unbudgeted items impacting comparability such as changes in accounting methods, workforce restructuring, and one-time occurrences will be excluded.

**2013 STIP Performance Targets**

| Category | Relative Weight | 2013 Target |
|---|---|---|
| Safety (includes both Public and Employee metrics) (1) | 40.0% | 1.000 |
| Customer (includes customer satisfaction and reliability) (2) | 35.0% | 1.000 |
| Financial (includes Earnings from Operations) | 25.0% | 1.000 |

1. Safety includes four subcomponents: (1) Nuclear Operations Safety, (2) Electric Operations Safety, (3) Gas Operations Safety, and (4) Employee Safety, all of which measure the Utility's safety performance with respect to each of those areas. The Committee will retain complete discretion to reduce the final Safety rating downward to zero based on the Companies' overall safety performance for 2013. The Companies' overall safety performance will be measured both by the quantitative measures described above and by qualitative performance. With respect to qualitative performance, the Committee will consider the collective impact that the Companies' business operations have had on public and employee safety.

2. Customer includes five subcomponents: (1) the overall satisfaction of customers, as measured through a quarterly survey, (2) the number of third party "dig-ins" (i.e., damage resulting in repair or replacement of underground facility) to the Utility's gas and electric assets, (3) the average duration of electricity outages experienced by all customers served, as measured by the System Average Interruption Duration Index , (4) how quickly gas asset information is entered into the Utility's gas mapping system after a gas project is completed, and (5) the Utility's ability to complete certain committed work for gas operations-related programs efficiently.

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.Exhibit 10.31

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
PG&E CORPORATION
(As Amended Effective as of January 1, 2013)

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan (" PLAN ") [1] for ELIGIBLE EMPLOYEES of PG&E Corporation (" CORPORATION "), Pacific Gas and Electric Company (" COMPANY ") and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN is the successor plan to the Supplemental Executive Retirement Plan of the COMPANY. The PLAN as contained herein was first adopted effective January 1, 2005.

No new participants can become eligible to accrue benefits under the PLAN on or after January 1, 2013, and existing participants in the PLAN as of January 1, 2013 shall cease to accrue further benefits under the Plan as of the date they become participants in Part III of the RETIREMENT PLAN.

ARTICLE 1

DEFINITIONS

1.01 Basic SERP Benefit shall mean the benefit described in Section 2.01.

1.02 Board or Board of Directors shall mean the BOARD OF DIRECTORS of the CORPORATION or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.

1.03 Company shall mean the Pacific Gas and Electric Company, a California corporation.

1.04 Corporation shall mean PG&E Corporation, a California corporation.

1.05 Eligible Employee shall mean individuals who are, prior to January 1, 2013 (1) (a) employees of the COMPANY or, with respect to PG&E Corporation, PG&E Corporation Support Services, Inc., and PG&E Corporation Support Services II, Inc. only, (i) prior to April 1, 2007, were employees who transferred to PG&E Corporation, PG&E Corporation Support Services, Inc., or PG&E Corporation Support Services II, Inc. from Pacific Gas and Electric Company; or (ii) after March 31, 2007, all employees, and (b) officers in Officer Bands I-V, or (2) such other employees of the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chief Executive Officer of the CORPORATION. ELIGIBLE EMPLOYEES shall not include employees who retired prior to January 1, 2005, or whose employment relationship with any of the PARTICIPATING EMPLOYERS was otherwise terminated prior to January 1, 2005.

1.06 STIP Payment shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by the CORPORATION prior to the date the ELIGIBLE EMPLOYEE becomes a participant in Part III of the RETIREMENT PLAN.

1.07 PART III of the RETIREMENT PLAN shall mean the cash balance benefit available under the RETIREMENT PLAN.

1.08 Participating Employer shall mean the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., and any other companies, affiliates, subsidiaries or associations designated by the Chief Executive Officer of the CORPORATION.

1.09 Plan shall mean the Supplemental Executive Retirement Plan ( " SERP " ) as set forth herein and as may be amended from time to time.

1.010 Plan Administrator shall mean the Employee Benefit Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.10 Retirement Plan shall mean the Pacific Gas and Electric Company Retirement Plan.

1.11 Salary shall mean the base salary received by an ELIGIBLE EMPLOYEE prior to the date the ELIGIBLE EMPLOYEE becomes a participant in Part III of the RETIREMENT PLAN. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to reflect amounts that have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.12 Service shall mean " credited service " as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, " credited service " as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE or after the date the ELIGIBLE EMPLOYEE becomes a participant in Part III of the RETIREMENT

PLAN.

ARTICLE 2

SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity with an annuity start date of the later of (a) the first of the month following the month in which the ELIGIBLE EMPLOYEE has a separation from service (as provided under Code Section 409A and related guidance), or (b) the first of the month following the ELIGIBLE EMPLOYEE's 55th birthday; provided, however, that no payments under the PLAN shall be made until the seventh month following the annuity start date. The first payment shall consist of the monthly annuity payment for the seventh month, plus the first six monthly annuity payments, including interest calculated at a rate to reflect the CORPORATION's marginal cost of funds. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

1.7% x the average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE x SERVICE x 1/12.

In computing a year's combination of SALARY and STIP PAYMENT, the year's amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years' SALARY, the average shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN (other than amounts paid or payable under Part III of the RETIREMENT PLAN), calculated before adjustments for marital or joint pension option elections.

The BASIC SERP BENEFIT is a benefit commencing at age 65. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.02 For ELIGIBLE EMPLOYEES of the PARTICIPATING EMPLOYERS, who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms that are actuarially equivalent within the meaning of Treasury Regulations Section 1.409A-2(b)(ii), with the first annuity payment commencing at the time set forth in Section 2.01:

(a) BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.

(b) A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE's death. Subject to the requirements of Treasury Regulations Section 1.409A-2(b)(ii), the factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.

An ELIGIBLE EMPLOYEE may make this election by the latest date permitted by the PLAN ADMINISTRATOR and in compliance with the rules of Treasury Regulations Section 1.409A-2(b)(2)(ii).

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension plans under Section 4l5 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN.

ARTICLE 3

SURVIVOR BENEFITS

3.01 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence, the PLAN ADMINISTRATOR shall pay a survivor's benefit ("SURVIVOR'S BENEFIT") to the ELIGIBLE EMPLOYEE's surviving spouse or BENEFICIARY ("Beneficiary" shall have the same meaning as provided under the

RETIREMENT PLAN):

(a) If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 or older at the time of death, the surviving spouse's or BENEFICIARY's benefit shall be a monthly annuity commencing at the time set forth in Section 2.01 and shall be payable for the life of the surviving spouse or BENEFICIARY. The amount of the monthly benefit shall be a monthly benefit that is actuarially equivalent to one-half of the monthly BASIC SERP BENEFIT that would have been paid to the ELIGIBLE EMPLOYEE calculated:

(i) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option; and

(ii) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and

(iii) without the application of early retirement reduction factors. However, if the surviving spouse or BENEFICIARY is more than 10 years younger than the ELIGIBLE EMPLOYEE, the amount of the surviving spouse's or BENEFICIARY's benefit shall be reduced one-twentieth of 1 percent for each full month in excess of 120 months' difference in their ages, except that such reduction shall not result in a SURVIVOR'S BENEFIT lower than would have been payable if the ELIGIBLE EMPLOYEE had retired as of the date of death and elected a 50 percent joint pension with a spouse of the same gender and age as the surviving spouse or BENEFICIARY.

(b) If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.01 (a)) at the time of death, the surviving spouse or BENEFICIARY will be entitled to receive a monthly annuity commencing at the time set forth in Section 2.01. The amount of the monthly annuity payable to the surviving spouse or BENEFICIARY shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments at age 55, and 4) had subsequently died.

(c) If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse or BENEFICIARY will be entitled to receive a monthly annuity at the time set forth in Section 2.01 in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.

(d) If a former ELIGIBLE EMPLOYEE was younger than age 55 and had fewer than 70 points (as calculated under Section 3.01(a)) at the time of his death, the surviving spouse or BENEFICIARY will be entitled to receive a monthly annuity at the time set forth in Section 2.01 in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT at age 55, and 3) had subsequently died.

3.02 A surviving spouse or BENEFICIARY who is entitled to receive a SURVIVOR'S BENEFIT under Section 3.01 shall not be entitled to receive any other benefit under the PLAN.

## ARTICLE 4

## ADMINISTRATIVE PROVISIONS

4.01 Administration. The PLAN shall be administered by the Senior Human Resources Officer of the CORPORATION ("PLAN ADMINISTRATOR"), who shall have the authority to interpret the PLAN and make and revise such rules as he or she deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 Amendment and Termination. The CORPORATION may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary notwithstanding, the CORPORATION may (but is not obligated to) reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant, is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the CORPORATION that preserves the time and form of payment rules under the PLAN and otherwise in a manner that complies with Code Section 409A, to the extent required to not violate Code Section 409A.

4.03 Nonassignability of Benefits. Except to the extent otherwise directed by a domestic relations order that the Plan Administrator determines is a Qualified Domestic Relations Order under Section 401(a)(12) of the Internal Revenue Code, the benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 Nonguarantee of Employment . Nothing contained in this PLAN shall be construed as a contract of employment between a PARTICPATING EMPLOYER and the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of a PARTICIPATING EMPLOYER, to remain as an officer of a PARTICIPATING EMPLOYER, or as a limitation on the right of a PARTICIPATING EMPLOYER to discharge any of its employees, with or without cause.

4.05 Apportionment of Costs . The costs of the PLAN may be equitably apportioned by the PLAN ADMINISTRATOR among the PARTICIPATING EMPLOYERS. Each PARTICIPATING EMPLOYER shall be responsible for making benefit payments pursuant to the PLAN on behalf of its ELIGIBLE EMPLOYEES or for reimbursing the CORPORATION for the cost of such payments, as determined by the CORPORATION in its sole discretion. In the event the respective PARTICIPATING EMPLOYER fails to make such payment or reimbursement, and the CORPORATION does not exercise its discretion to make the contribution on such PARTICIPATING EMPLOYER's behalf, future benefit accruals of the ELIGIBLE EMPLOYEES of that PARTICIPATING EMPLOYER shall be suspended. If at some future date, the PARTICIPATING EMPLOYER makes all past-due contributions, plus interest at a rate determined by the PLAN ADMINISTRATOR in his or her sole discretion, the benefit accrual of its ELIGIBLE EMPLOYEES will be recognized for the period of the suspension.

4.06 Benefits Unfunded and Unsecured . The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the CORPORATION.

4.07 Applicable Law . All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California. The PLAN is intended to comply with the provisions of Code Section 409A. However, the CORPORATION makes no representation that the benefits provided under this PLAN will comply with Code Section 409A and makes no undertaking to prevent Code Section 409A from applying to the benefits provided under this PLAN or to mitigate its effects on any deferrals or payments made under this PLAN.

4.08 Satisfaction of Claims . Notwithstanding Section 4.05 or any other provision of the PLAN, the CORPORATION may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the CORPORATION and shall be subject to the ELIGIBLE EMPLOYEE' s acknowledgement that the CORPORATION's obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the CORPORATION may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

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[1] Words in all capitals are defined in Article I.

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.Exhibit 10.32

**PG&E CORPORATION**
**DEFINED CONTRIBUTION EXECUTIVE SUPPLEMENTAL RETIREMENT PLAN**

Effective as of January 1, 2013 (the "Effective Date"), PG&E Corporation adopts this Plan for the benefit of a select group of management or highly compensated employees of PG&E Corporation and its Participating Subsidiaries. The Plan is an unfunded arrangement and is intended to be exempt from the participation, vesting, funding and fiduciary requirements set forth in Title I of ERISA.

**Article 1 – Definitions**

When used in this Plan, the following words, terms and phrases have the meanings given to them in this Article unless another meaning is expressly provided elsewhere in this document. When applying these definitions and any other word, term or phrase used in this Plan, the form of any word, term or phrase will include any and all of its other forms.

1.01 " **Accoun t** " means the bookkeeping account established for each Eligible Employee as provided in Section 5.01 hereof.

1.02 " **Aggregated Plan"** means any arrangement that, along with this Plan, would be treated as a single nonqualified deferred compensation plan under Treasury Regulation Section 1.409A-
1(c)(2).

1.03 " **Board** " means the Board of Directors of Company.

1.04 " **Code** " means the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.

1.05 " **Committee** " means the Compensation Committee of the Board, as it may be constituted from time to time.

1.06 " **Company** " means PG&E Corporation, a California corporation.

1.07 " **Company Contribution** " means a deemed contribution that is credited to an Eligible Employee's Account in accordance with the terms of Article 2 hereof.

1.08 " **Eligible Employee** " means any individual who (i) was a participant in the SERP and elects to switch under the Pacific Gas and Electric Company Retirement Plan for Management Employees to a cash-balance formula pension benefit effective January 1, 2014, (ii) becomes an Officer in Bands I-V of Company or a Participating Subsidiary on or after the Effective Date; or (iii) is an employee of Company or a Participating Employer, and is designated as a Plan Participant by the Chief Executive Officer of Company. Notwithstanding the forgoing, any individual who is a participant in the Excess Plan shall not become an Eligible Employee until January 1 of the calendar year after satisfying any of the criteria in (ii)-(iii) above. If an individual ceases to be an Officer in Bands I-V or if his or her participation in this Plan is terminated by the Chief Executive Officer, then any accrued benefits will be handled in accordance with Article 6.

1.09 " **Employer** " means any entity that employs an Eligible Employee, whether that entity is the Company or any of the Participating Subsidiaries designated by the Plan Administrator.

1.10 " **ERISA** " means the Employee Retirement Income Security Act of 1974, as amended.

1.11 " **Excess Plan** " means the Retirement Excess Plan of the Pacific Gas and Electric Company, as amended from time to time.

1.12 " **Investment Fund** " means each deemed investment vehicle which serves as a means to measure value, increases or decreases with respect to an Eligible Employee's Account.

1.13 " **Participating Subsidiary"** means a United States-based subsidiary of Company, which has been designated by the Plan Administrator as a Participating Subsidiary under this Plan and which has agreed to make payments or reimbursements with respect to its Eligible Employees pursuant to Section 11.04. At such times and under such conditions as the Plan Administrator may direct, one or more other subsidiaries of Company may become Participating Subsidiaries or a Participating Subsidiary may be withdrawn from the Plan. An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.

1.14 " **Plan** " means the PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan.

1.15 " **Plan Year** " means each calendar year during which the Plan is in effect

1.16 " **SERP** " means the Supplemental Executive Retirement Plan of PG&E Corporation, as amended from time to time.

1.17 " **Salary** " means only the gross amount of an Eligible Employee's base salary as reflected in the payroll records of the applicable Employer. Salary shall not include amounts received by an employee after such employee ceases to be an Eligible Employee or prior to

becoming an Eligible Employee. Salary shall be calculated before reduction for compensation voluntarily deferred or contributed by the Eligible Employee pursuant to all qualified or nonqualified plans of the applicable Employer and shall be calculated to include amounts not otherwise included in the Eligible Employee's gross income under Code Sections 125, 132, 402(e)(3), 402(h), or 403(b) pursuant to plans or arrangements established by the Employers; provided, however, that all such amounts will be included in compensation only to the extent that had there been no such plan, the amount would have been payable in cash to the Eligible Employee. Without limiting the foregoing, "Salary" shall not include any amount paid pursuant to a disability plan or pursuant to a disability insurance policy or distributions from nonqualified deferred compensation plans, incentive payments of any kind, commissions, overtime, fringe benefits, or any non-cash benefit.

1.18 "S **eparation from Service** " means a "separation from service" with Company and its Affiliates within the meaning of Code Section 409A(a)(2)(A)(i) and related Treasury Regulations and other guidance, as determined by the Plan Administrator in its discretion.

1.19 " **STIP Payment** " means the gross amount of an Eligible Employee's bonus under the annual cash Short-Term Incentive Plan adopted and maintained each year by Company or its Participating Subsidiaries. STIP Payments shall not include amounts received by an employee after such employee ceases to be an Eligible Employee or prior to becoming an Eligible Employee. For purposes of calculating benefits under the Plan, STIP Payment shall be calculated before reduction for compensation voluntarily deferred or contributed by the Eligible Employee pursuant to all qualified or nonqualified plans of the applicable Employer, and shall be calculated to include amounts not otherwise included in the Eligible Employee's gross income under Code Sections 125, 132, 402(e)(3), 402(h), or 403(b) pursuant to plans or arrangements established by the Employer; provided, however, that all such amounts will be included in compensation only to the extent that had there been no such plan, the amount would have been payable in cash to the Eligible Employee.

1.20 **"Valuation Date"** means:

(1) For purposes of valuing Plan assets and Eligible Employees' Accounts for periodic reports and statements, the date as of which such reports or statements are made; and

(2) For purposes of determining the amount of assets actually distributed to the Eligible Employee, his or her beneficiary, or an Alternate Payee (or available for withdrawal), a date that shall not be more than thirty business days prior to the date the check is issued to the Eligible Employee.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

## Article 2 - Company Contributions

2.01 **Company Contribution s** . Company will make a deemed contribution to each Eligible Employee's Account in a percentage amount designated by the Committee, in its sole discretion, of the Eligible Employee's Salary and STIP Payment, at the time that such Salary or STIP Payment is paid.

2.02 **Excess Plan Participants** . Company will make an additional deemed contribution to the Account of each Eligible Employee who was a participant in the Excess Plan on or after January 1, 2013. The amount of such contribution will be approximately equal to the difference between the amounts that the Eligible Employee could have received under the Plan if contributions, if any, under Section 2.01 had commenced upon satisfying any of the eligibility criteria in Section 1.08(ii)-(iii), and the amount actually accrued under the Excess Plan, in each case through December 31 of such year. Such payments shall be made only for the portion of the calendar year prior to the individual becoming an Eligible Employee. Such calculation shall be done at the Company's discretion, using such assumptions and methodologies as determined by the Company in its sole discretion. Amounts provided pursuant to this Section will distributed in a lump-sum, in accordance with Section 6.01 (2).

## Article 3 - Vesting

3.01 **Vesting of Company Contribution s** . Except as otherwise determined by the Plan Administrator in its sole discretion, and provided that the Eligible Employee has not Separated from Service, an Eligible Employee shall become one hundred percent (100%) vested in the Eligible Employee's Account after completing at least three (3) cumulative years of service with any Employer(s). For this purpose, years of service shall be calculated on an elapsed-time, anniversary date of hire basis. "Years of cumulative service" shall include all service while an active participant in the Plan or in the SERP, including active service prior to any break in service. An Employee's service will be deemed to continue while on approved leave of absence.

3.02 **Amounts Not Veste d** . Subject to the foregoing, any amounts credited to an Eligible Employee's Account that are not vested at the time of the Eligible Employee's Separation from Service shall be forfeited.

## Article 4 – Investment Funds

Although no assets will be segregated or otherwise set aside with respect to an Eligible Employee's Account, the amount that is ultimately payable to the Eligible Employee with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Eligible Employees' Accounts. Such procedures generally

shall provide that an Eligible Employee's Account shall be deemed to be invested among the available Investment Funds in the manner elected by the Eligible Employee in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Eligible Employee, such Account will be deemed to be invested in the Investment Funds designated by the Plan Administrator. Eligible Employees shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, an Eligible Employee may not reallocate Account balances between Investment Funds if such reallocation would result in a non-exempt Discretionary Transaction as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested. The available Investment Funds shall be designated by the Plan Administrator and may be changed from time to time by the Plan Administrator at its discretion.

**Article 5 - Accountings**

5.01 **Eligible Employees' Accounts** . At the direction of the Plan Administrator, there shall be established and maintained on the books of the Employer, a separate account for each Eligible Employee in order to reflect his or her interest under the Plan.

5.02 **Investment Earnings** . Each Eligible Employee's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts credited thereto. Each Eligible Employee's Account shall also be credited (or debited) with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Eligible Employee's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Eligible Employee's Account.

5.03 **Accounting Methods** . The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Eligible Employees' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be revised from time to time but shall conform to the extent practicable with the accounting methods used under the Plan.

5.04 **Valuations and Reports** . The fair market value of each Eligible Employee's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Eligible Employees' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Eligible Employee's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.

5.05 **Statements of Eligible Employee's Accounts** . Each Eligible Employee shall be furnished with periodic statements of his or her interest in the Plan.

**Article 6 - Distributions.**

6.01 **Distribution of Account Balances** .

(1) **Participants in SERP.** Distribution of the balance credited to the Account of any Eligible Employee who was a participant in the SERP will be made according to the time and form provisions applicable to that Eligible Employee's benefits under the SERP. Sections 6.01(2), 6.02, 6.03, 6.04 and 6.05 shall not apply to the Eligible Employees described above in this Section 6.01(1).

(2) **Other Eligible Employees.** Except to the extent the Eligible Employee has elected otherwise under this Section 6 at the time of deferral, distribution of the balance credited to an Eligible Employee's Account shall be made in a single lump sum as soon as reasonably practicable (but in any event within 90 days) following the date that is seven (7) months following Separation from Service.

(3) **DROs.** In the case of an Alternate Payee (as defined in Section 7.01(1)), to the extent allowable under Code Section 409A, distribution shall be made as directed in a domestic relations order approved by the Plan Administrator, but only as to the portion of the Eligible Employee's Account which the domestic relations order states is payable to the Alternate Payee.

6.02 **Election of Installment Payments** . In lieu of the single sum payment under Section 6.01, an Eligible Employee may elect in writing, on such form or in such other manner as it may prescribe, and file with the Plan Administrator an election that payment of amounts credited to the Eligible Employee's Account be made in from 2 to 10 equal annual installments. Installment payments will be considered separate payments for purposes of Code Section 409A and will commence as soon as reasonably practicable (but in any event within 90 days) following the date that is seven (7) months following Separation from Service ("Benefit Commencement Date"), and subsequent installments will be paid on each anniversary of the Benefit Commencement Date thereof until all installments are paid. However, if during the installment payment period after the Benefit Commencement Date the Account balance plus the Eligible Employee's interest in all other Aggregated Plans is less than the dollar limit set forth in Code Section 402(g)(1)(B) in the aggregate, the value of the remaining installments and such other interest(s) may be accelerated by written election of the Plan Administrator and subsequently paid as a lump sum at the sole discretion of the Plan Administrator, except to the extent that would result in a violation of Code Section 409A. Notwithstanding anything in this Section 6.02 to the contrary, if the Eligible Employee's vested Account balance on the Benefit Commencement Date is less than $50,000, then the distribution election described in this Section 6.02 shall be disregarded and the Eligible Employee's entire vested Account balance shall be paid in a lump sum distribution as described in Section 6.01(2) above.

6.03 **Timing of Elections.**

(1) **General Rule.** The election described in Section 6.02 shall be made no later than December 31 of the calendar year immediately

preceding the calendar year in which the Salary or STIP Payment commences to be earned that is the basis of the Company Contribution for which an election is being made, in accordance with such procedures established by the Company in its sole discretion.

**(2) Initial Eligibility.** Notwithstanding Section 6.03(1), an Eligible Employee that is newly eligible to participate in the Plan (or in any Aggregated Plan) must make an election regarding whether distributions shall be made in a lump-sum or installments, as provided in Section 6.02. Such election must be made within thirty (30) days after he or she first becomes an Eligible Employee (or within such other earlier deadline as may be established by the Company, in its sole discretion) but only with respect to Company Contributions attributable to Salary and STIP Payments that are paid with respect to services performed after such election is made; provided, however, that for this purpose only such thirty (30) day period shall begin to run on the date that the Eligible Employee first becomes eligible to participate in this Plan (or, if earlier, any Aggregated Plan). In the event an Eligible Employee fails to timely make such election, Section 6.01(2) shall apply. Notwithstanding anything to the contrary herein, no Company Contributions shall be earned or made to a newly Eligible Employee's Account with respect to service performed prior to the earlier of (1) the day after the Eligible Employee returns an initial election pursuant to Section 6.03(2) or (2) 31 days after the individual first qualifies as an Eligible Employee.

(3) **Performance-Based Compensation.** Notwithstanding Section 6.03(1), with respect to STIP Payments that qualify as "Performance-Based Compensation," the Company may, in its sole discretion, permit an election pertaining to Company Contributions attributable to such Performance-Based Compensation to be made no later than six (6) months before the end of the performance service period and in accordance with Code Section 409A. For this purpose, "Performance-Based Compensation" shall be compensation, the payment or amount of which is contingent on pre-established organizational or individual performance criteria, which satisfies the requirements of Code Section 409A.

6.04 **Change in Distribution Election** . An Eligible Employee may change a distribution election previously made pursuant to Section 6.02 only in accordance with the rules under Code Section 409A. Generally, a subsequent election pursuant to this Section 6.04: (1) cannot take effect for twelve (12) months, (2) must occur at least twelve (12) months before the first scheduled payment, and (3) must defer a previously elected distribution at least five (5) additional years. The Plan Administrator may establish additional rules or restrictions on changes in distribution elections.

6.05 **Death Distributions** . If an Eligible Employee dies before the balance of his or her Account has been distributed (whether or not the Eligible Employee had previously had a Separation from Service), the Eligible Employee's Account shall be distributed in a single lump sum to the beneficiary designated or otherwise determined in accordance with Section 6.07, as soon as practicable the date of death (but in any event within 90 days after the date of death).

6.06 **Effect of Change in Eligible Employee Status** . If an Eligible Employee ceases to be an Eligible Employee but does not experience a Separation from Service, the balance credited to his or her Account shall continue to be credited (or debited) with appreciation, depreciation, earnings, gains or losses under the terms of the Plan and shall be distributed to him or her at the time and in the manner set forth in this Section 6.

6.07 **Payments to Incompetents** . If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or institution receiving the payment shall be a valid and complete discharge of any liability of Company with respect to any benefit so paid.

6.08 **Beneficiary Designations** . Each Eligible Employee may designate, in a signed writing delivered to the Plan Administrator, on such form or in such other manner as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Eligible Employee's death. Such an Eligible Employee may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan Administrator shall supersede all prior designations. If such an Eligible Employee dies without having designated a beneficiary or if no beneficiary survives that Eligible Employee, that Eligible Employee's Account shall be payable to the beneficiary or beneficiaries designated or otherwise determined under the PG&E Corporation Retirement Savings Plan or any predecessor qualified retirement plan sponsored by Company or any of its subsidiary companies.

6.09 **Undistributable Accounts** . Each Eligible Employee and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Eligible Employee or beneficiary to whom an Eligible Employee's Account is payable under this Section 6, the Eligible Employee's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 6, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto. Company shall have the right to assign or transfer the liability for payment of any undistributable Account to the Eligible Employee's former Employer (or any successor thereto).

6.10 **Plan Administrator Discretion** . Within the specific time periods described in this Section 6, the Plan Administrator shall have

sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

## Article 7 - Domestic Relations Orders.

7.01 **Domestic Relations Orders** . The Plan Administrator shall establish written procedures for determining whether a domestic relations order purporting to dispose of any portion of an Eligible Employee's Account is a domestic relations order within the meaning of Section 414(p) of the Code that is acceptable to the Plan (a "DRO").

**(1)** **No Payment Unless a DRO** . No payment shall be made to any person designated in a domestic relations order (an " **Alternate Payee** ") until the Plan Administrator (or a court of competent jurisdiction reversing an initial adverse determination by the Plan Administrator) determines that the order is a DRO. Payment shall be made to each Alternate Payee as specified in the DRO.

**(2)** **Time of Payment** . Payment may be made to an Alternate Payee in the form of a lump sum, at the time specified in the DRO, but no earlier than the date the DRO determination is made by the Plan.

**(3)** **Hold Procedures** . Notwithstanding any contrary Plan provision, prior to the receipt of a domestic relations order, the Plan Administrator may, in its sole discretion, place a hold upon all or a portion of an Eligible Employee's Account for a reasonable period of time (as determined by the Plan Administrator in accordance with Code Section 409A) if the Plan Administrator receives notice that (a) a domestic relations order is being sought by the Eligible Employee, his or her spouse, former spouse, child or other dependent, and (b) the Eligible Employee's Account is a source of the payment under such domestic relations order. For purposes of this Section 7.01, a "hold" means that no withdrawals, distributions, or investment transfers may be made with respect to an Eligible Employee's Account. If the Plan Administrator places a hold upon an Eligible Employee's Account pursuant to this Section 7.01, it shall inform the Eligible Employee of such fact.

## Article 8 - Tax Withholding

Each Eligible Employee shall be responsible for FICA taxes on amounts credited to his or her Account under Section 2. Without limiting the foregoing, the applicable Employer shall have the right to withhold such amounts from other payments due to the Eligible Employee. Company Contributions will not be reduced to cover Eligible Employees' FICA tax liabilities.

The applicable Employer, as applicable, will withhold from other amounts owed to an Eligible Employee or require the Eligible Employee to remit to Employer, as applicable, an amount sufficient to satisfy federal, state and local tax withholding requirements with respect to any Plan benefit or the vesting, payment or cancellation of any Plan benefit.

## Article 9 - Administration of the Plan .

9.01 **Plan Administrator** . The Employee Benefit Committee of Company is hereby designated as the administrator of the Plan (within the meaning of Section 3(16)(A) of ERISA). The Plan Administrator delegates to the most senior human resource officer for Company, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.

9.02 **Powers of Plan Administrator** . The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.

9.03 **Decisions of Plan Administrator** . All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

## Article 10 - Modification or Termination of Plan .

10.01 **Employers' Obligations Limited** . The Plan is voluntary on the part of the Employers, and the Employers do not guarantee to continue the Plan. Company at any time may, by appropriate amendment of the Plan, or suspend Company Contributions , with or without cause.

10.02 **Right to Amend or Terminate** . The Board of Directors, acting through the Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.

**(1)** **Limitations** . Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.

**(2)** **Appendices** . Notwithstanding the above, the Plan Administrator may amend the Appendices in its discretion.

10.03 **Effect of Termination** . If the Plan is terminated, the balances credited to the Accounts of the Eligible Employees affected by such termination shall be distributed to them at the time and in the manner set forth in Section 6; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Eligible Employees' Accounts to the extent provided in Treasury Regulation Sections 1-409A-3(j)(4)(ix) (A) (relating to terminations in connection with certain corporate dissolutions), (B) (relating to terminations in

connection with certain change of control events), and (C) (relating to general terminations).

## Article 11 - General Provisions

11.01 **Inalienability** . Except to the extent otherwise directed by a domestic relations order which the Plan Administrator determines is a DRO (as defined in Section 7.01) or mandated by applicable law, in no event may either an Eligible Employee, a former Eligible Employee or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.

11.02 **Rights and Duties** . Neither the Employers nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.

11.03 **No Enlargement of Employment Rights** . Neither the establishment or maintenance of the Plan nor any action of any Employer or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as an Employee nor, upon dismissal, any right or interest in any specific assets of the Employers other than as provided in the Plan. Each Employer expressly reserves the right to discharge any Employee at any time, with or without cause or advance notice.

11.04. **Apportionment of Costs and Duties** . All acts required of the Employers under the Plan may be performed by Company for itself and its Participating Subsidiaries, and the costs of the Plan may be equitably apportioned by the Plan Administrator among Company and the other Employers. Whenever an Employer is permitted or required under the terms of the Plan to do or perform any act, matter or thing, it shall be done and performed by any officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer. Each Participating Subsidiary shall be responsible for making benefit payments pursuant to the Plan on behalf of its Eligible Employees or for reimbursing Company for the cost of such payments, as determined by Company in its sole discretion. In the event the respective Participating Subsidiary fails to make such payment or reimbursement, and Company does not exercise its discretion to make the payment on such Participating Subsidiary’s behalf, participation in the Plan by the Eligible Employees of that Participating Subsidiary shall be suspended in a manner consistent with Code Section 409A. If at some future date, the Participating Subsidiary makes all past-due payments and reimbursements, plus interest at a rate determined by Company in its sole discretion, the suspended participation of its Eligible Employees eligible to participate in the Plan will be recognized in a manner consistent with Code Section 409A. In the event the respective Participating Subsidiary fails to make such payment or reimbursement, an Eligible Employee’s (or other payee’s) sole recourse shall be against the respective Participating Subsidiary, and not against Company. An Eligible Employee’s participation in the Plan shall constitute agreement with this provision.

11.05 **Applicable Law** . The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California and, to the extent applicable, ERISA. The Plan is intended to comply with the provisions of Code Section 409A. However, Company makes no representation that the benefits provided under the Plan will comply with Code Section 409A and makes no undertaking to prevent Code Section 409A from applying to the benefits provided under the Plan or to mitigate its effects on any deferrals or payments made under the Plan.

11.06 **Severability** . If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.

11.07 **Captions** . The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

**APPENDIX A**
**PARTICIPATING SUBSIDIARIES**
**(As of January 1, 2013)**

– Pacific Gas and Electric Company
– All U.S. subsidiaries of PG&E Corporation or the above-named corporation(s)

**Director Compensation**

**RESOLUTION OF THE**
**BOARD OF DIRECTORS OF**
**PG&E CORPORATION**

September 18, 2012

BE IT RESOLVED that, effective January 1, 2013, advisory directors and directors who are not employees of this corporation or Pacific Gas and Electric Company (collectively, "non-employee directors") shall be paid a retainer of $15,000 per calendar quarter, which shall be in addition to fees paid for attendance at Board meetings, Board committee meetings, and shareholder meetings; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, the non-employee director who serves as lead director shall be paid an additional retainer of $12,500 per calendar quarter; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, the non-employee director who is duly appointed to chair the Audit Committee of this Board shall be paid an additional retainer of $12,500 per calendar quarter, the non-employee director who is duly appointed to chair the Compensation Committee of this Board shall be paid an additional retainer of $3,750, and the non-employee directors who are duly appointed to chair the other permanent committees of this Board shall be paid an additional retainer of $2,500 per calendar quarter; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, each non-employee director shall be paid a fee of $1,750 for each meeting of the Board and each meeting of a Board committee (of which such non-employee director is a member) attended; provided, however, that each non-employee director who is a member of the Audit Committee shall be paid a fee of $2,750 for each meeting of the Audit Committee attended; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, non-employee directors attending any meeting of this corporation's shareholders that is not held on the same day as a meeting of this Board shall be paid a fee of $1,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that non-employee directors shall be eligible to participate in the PG&E Corporation 2006 Long-Term Incentive Plan under the terms and conditions of that Plan, as adopted by this Board and as may be amended from time to time; and

BE IT FURTHER RESOLVED that members of this Board shall be reimbursed for reasonable expenses incurred in connection with attending Board, Board committee, or shareholder meetings, or participating in other activities undertaken on behalf of this corporation; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, the resolution on this subject adopted by the Board of Directors on December 15, 2010 is hereby superseded.

**Director Compensation**

**RESOLUTION OF THE**
**BOARD OF DIRECTORS OF**
**PACIFIC GAS AND ELECTRIC COMPANY**

September 18, 2012

BE IT RESOLVED that, effective January 1, 2013, advisory directors and directors who are not employees of this company or PG&E Corporation (collectively, "non-employee directors") shall be paid a retainer of $15,000 per calendar quarter, which shall be in addition to any fees paid for attendance at Board meetings, Board committee meetings, and shareholder meetings; provided, however, that a non-employee director shall not be paid a retainer by this company for any calendar quarter during which such director also serves as a non-employee director of PG&E Corporation; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, the non-employee director who serves as lead director shall be paid an additional retainer of $12,500 per calendar quarter; provided, however, that a non-employee director who serves as lead director shall not be paid an additional retainer by this company for any calendar quarter during which such director also serves as lead director of the PG&E Corporation Board of Directors; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, the non-employee director who is duly appointed to chair the Audit Committee of this Board shall be paid an additional retainer of $12,500 per calendar quarter, and the non-employee directors who are duly appointed to chair the other permanent committees of this Board shall be paid an additional retainer of $2,500 per calendar quarter; provided, however, that a non-employee director duly appointed to chair a permanent committee of this Board shall not be paid an additional retainer by this company for any calendar quarter during which such director also serves as chair of the corresponding committee of the PG&E Corporation Board of Directors; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, each non-employee director attending any meeting of the Board that is not held concurrently or sequentially with a meeting of the Board of Directors of PG&E Corporation, or any meeting of a Board committee (of which such non-employee director is a member) that is not held concurrently or sequentially with a meeting of the corresponding committee of the PG&E Corporation Board, shall be paid a fee of $1,750 for each such Board or Board committee meeting attended; provided, however, that each non-employee director who is a member of the Audit Committee of this Board attending any meeting of such Audit Committee that is not held concurrently or sequentially with a meeting of the Audit Committee of the PG&E Corporation Board shall be paid a fee of $2,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, non-employee directors attending any meeting of this company's shareholders that (1) is not held on the same day as a meeting of this Board or a meeting of the Board of Directors of PG&E Corporation, and (2) is not held concurrently or sequentially with a meeting of the shareholders of PG&E Corporation shall be paid a fee of $1,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that members of this Board shall be reimbursed for reasonable expenses incurred in connection with attending Board, Board committee, or shareholder meetings, or participating in other activities undertaken on behalf of this company; and

BE IT FURTHER RESOLVED that, effective January 1, 2013, the resolution on this subject adopted by the Board of Directors on December 15, 2010 is hereby superseded.

# PG&E Corporation

# 2006 Long-Term Incentive Plan

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PLAN HISTORY AND NOTES TO COMPANY

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| December 15, 2004 | Board adopts Plan with a reserve of 12 million shares. |
| April 20, 2005 | Shareholders approve Plan. |
| January 1, 2006 | Plan Effective Date |
| February 15, 2006 | Change in control provisions are amended |
| December 20, 2006 | Board amends Section 7 containing the terms for automatic awards for Non-Employee Directors, effective January 1, 2007 |
| October 17, 2007 | Board amends Section 7 as follows:<br>Define "Grant Date" for a particular calendar year as the first business day in March of that calendar year. Previously, the grant date for awards in 2006 and 2007 was the first business day in January of that particular calendar year. This amendment becomes effective starting with grants for 2008.<br>Amend the basis for calculating the per share value of stock option awards, so it is based on the average closing price of Stock during the months of November, December, and January preceding the grant. Previously, the per share value of stock options awards for grants in 2006 and 2007 was based on the average closing price of Stock during the preceding month of November. This amendment becomes effective starting with grants for 2008.<br>Clarify the language for settling restricted stock awards upon a Nonemployee Director's retirement from the Board, to indicate that shares credited to a Nonemployee Director's Restricted Stock Unit account may be settled after a Nonemployee Director ceases to be a member of the Board of Directors following five years of service on the Board. |
| September 17, 2008 | Board amends Section 7 containing the terms for automatic awards for Nonemployee Directors, effective January 1, 2009, to increase the total value of annual equity awards to Nonemployee Directors from $80,000 to $90,000. Of this amount, $45,000 of equity awards shall be Restricted Stock, and the remaining $45,000 shall be a mixture of Options and Restricted Stock Units, consistent with the Plan and with each Nonemployee Director's election. |
| Effective January 1, 2009 | Plan is amended to comply with the final regulations under Section 409A of the Code |
| February 18, 2009 | Plan is amended to delay grant and pricing of 2009 grants for non-employee directors, to be consistent with 2009 grants to employees. |
| December 16, 2009 | Plan is amended to (1) establish March 10, 2010 as the date of grant of 2010 Plan awards for non-employee directors and calculate the number of shares of restricted stock and restricted stock units (RSUs) to be awarded based upon the average closing price of PG&E Corporation common stock over the five trading days on March 4 through March 10, 2010, and (2) beginning in March 2011, establish that the date of grant of Plan awards for non-employee directors and the price of PG&E Corporation common stock to be used to calculate the number of shares of restricted stock and RSUs to be awarded to non-employee directors be the same as the date of grant and stock price used for the annual LTIP awards for employees. |
| May 12, 2010 | Plan is amended (following approval from the PG&E Corporation Board of Directors and shareholders) to obtain reapproval of the material terms of performance goals, as amended, to have the compensation paid based on these performance goals be eligible for full deductibility under Section 162(m) of the Internal Revenue Code. |
| December 15, 2010 | Plan is amended such that (1) all Nonemployee Director LTIP awards are comprised solely of RSUs granted upon a director's election to the Board of Directors of PG&E Corporation to serve a one-year term, which vest at the completion of the one-year term of service (unless vesting occurs earlier due to enumerated events and (2) the LTIP prohibits option/SAR cash buyouts or recycling. |
| June 15, 2011 | Plan is amended such that the number of annual RSUs granted to Nonemployee directors is rounded down to the nearest whole number. (Previously, the number of RSUs granted included fractional units calculated to three decimal points.) |
| January 1, 2013 | Section 7 of the Plan is amended to (1) increase the value of annual equity awards to Nonemployee Directors from $90,000 to $105,000 and (2) permit deferral of non-employee director awards that are granted pursuant to section 7 of the Plan. |

# PG&E Corporation
# 2006 Long-Term Incentive Plan

(As adopted effective January 1, 2006, and
as amended effective on February 15, 2006, December 20, 2006, October 17, 2007, September 17, 2008, January 1, 2009, February 18, 2009, December 16, 2009, May 12, 2010, December 15, 2010, June 15, 2011, and January 1, 2013)

1. **Establishment, Purpose and Term of Plan .**

1.1 **Establishment .** The PG&E Corporation 2006 Long-Term Incentive Plan (the " ***Plan*** " ) is hereby established effective as of January 1, 2006 (the " ***Effective Date*** " ), provided it has been approved by the shareholders of the Company.

1.2 **Purpose .** The purpose of the Plan is to advance the interests of the Participating Company Group and its shareholders by providing an incentive to attract and retain the best qualified personnel to perform services for the Participating Company Group, by motivating such persons to contribute to the growth and profitability of the Participating Company Group, by aligning their interests with interests of the Company's shareholders, and by rewarding such persons for their services by tying a significant portion of their total compensation package to the success of the Company. The Plan seeks to achieve this purpose by providing for Awards in the form of Options, Stock Appreciation Rights, Restricted Stock Awards, Performance Shares, Performance Units, Restricted Stock Units, Deferred Compensation Awards and other Stock-Based Awards as described below.

1.3 **Term of Plan.** The Plan shall continue in effect until the earlier of its termination by the Board or the date on which all of the shares of Stock available for issuance under the Plan have been issued and all restrictions on such shares under the terms of the Plan and the agreements evidencing Awards granted under the Plan have lapsed. However, all Awards shall be granted, if at all, within ten (10) years from the Effective Date. Moreover, Incentive Stock Options shall not be granted later than ten (10) years from the date of shareholder approval of the Plan.

2. **Definitions and Construction .**

2.1 **Definitions.** Whenever used herein, the following terms shall have their respective meanings set forth below:

(a) " ***Affiliate*** " means (i) an entity, other than a Parent Corporation, that directly, or indirectly through one or more intermediary entities, controls the Company or (ii) an entity, other than a Subsidiary Corporation, that is controlled by the Company directly, or indirectly through one or more intermediary entities. For this purpose, the term "control" (including the term "controlled by") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of the relevant entity, whether through the ownership of voting securities, by contract or otherwise; or shall have such other meaning assigned such term for the purposes of registration on Form S-8 under the Securities Act.

(b) " ***Award*** " means any Option, SAR, Restricted Stock Award, Performance Share, Performance Unit, Restricted Stock Unit or Deferred Compensation Award or other Stock-Based Award granted under the Plan.

(c) " ***Award Agreement*** " means a written agreement between the Company and a Participant setting forth the terms, conditions and restrictions of the Award granted to the Participant.

(d) " ***Board*** " means the Board of Directors of the Company.

(e) " ***Change in Control*** " means, unless otherwise defined by the Participant's Award Agreement or contract of employment or service, the occurrence of any of the following:

(i) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any benefit plan for Employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act), of stock of the Company representing twenty percent (20%) or more of the combined voting power of the Company's then outstanding voting stock; or

(ii) during any two consecutive years, individuals who at the beginning of such period constitute the Board cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds (2/3) of the Directors then still in office who were Directors at the beginning of the period; or

(iii) the consummation of any consolidation or merger of the Company other than a merger or consolidation which would result in the voting stock of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting stock of the surviving entity or any parent of such surviving entity) at least seventy percent (70%) of the Combined Voting Power of the Company, such surviving entity or the parent of such surviving entity outstanding immediately after the merger or consolidation; or



(iv) the approval of the Shareholders of the Company of any (1) sale, lease, exchange or other transfer (in one or a

series of related transactions) of all or substantially all of the assets of the Company, or (2) any plan or proposal for the liquidation or dissolution of the Company.

For purposes of paragraph (iii), the term ***"Combined Voting Power"*** shall mean the combined voting power of the Company's or other relevant entity's then outstanding voting stock.

(f) " ***Code*** " means the Internal Revenue Code of 1986, as amended, and any applicable regulations promulgated thereunder.

(g) " ***Committee*** " means the Compensation Committee or other committee of the Board duly appointed to administer the Plan and having such powers as shall be specified by the Board. If no committee of the Board has been appointed to administer the Plan, the Board shall exercise all of the powers of the Committee granted herein, and, in any event, the Board may in its discretion exercise any or all of such powers.

(h) " ***Company*** " means PG&E Corporation, a California corporation, or any successor corporation thereto.

(i) " ***Consultant*** " means a person engaged to provide consulting or advisory services (other than as an Employee or a member of the Board) to a Participating Company, provided that the identity of such person, the nature of such services or the entity to which such services are provided would not preclude the Company from offering or selling securities to such person pursuant to the Plan in reliance on registration on a Form S-8 Registration Statement under the Securities Act.

(j) " ***Deferred Compensation Award*** " means an award of Stock Units granted to a Participant pursuant to Section 12 of the Plan.

(k) " ***Director*** " means a member of the Board.

(l) " ***Disability*** " means the permanent and total disability of the Participant, within the meaning of Section 22(e)(3) of the Code, except as otherwise set forth in the Plan or an Award Agreement.

(m) " ***Dividend Equivalent*** " means a credit, made at the discretion of the Committee or as otherwise provided by the Plan, to the account of a Participant in an amount equal to the cash dividends paid on one share of Stock for each share of Stock represented by an Award held by such Participant.

(n) " ***Employee*** " means any person treated as an employee (including an Officer or a member of the Board who is also treated as an employee) in the records of a Participating Company and, with respect to any Incentive Stock Option granted to such person, who is an employee for purposes of Section 422 of the Code; provided, however, that neither service as a member of the Board nor payment of a director's fee shall be sufficient to constitute employment for purposes of the Plan. The Company shall determine in good faith and in the exercise of its discretion whether an individual has become or has ceased to be an Employee and the effective date of such individual's employment or termination of employment, as the case may be. For purposes of an individual's rights, if any, under the Plan as of the time of the Company's determination, all such determinations by the Company shall be final, binding and conclusive, notwithstanding that the Company or any court of law or governmental agency subsequently makes a contrary determination.

(o) " ***Exchange Act*** " means the Securities Exchange Act of 1934, as amended.

(p) " ***Fair Market Value*** " means, as of any date, the value of a share of Stock or other property as determined by the Committee, in its discretion, or by the Company, in its discretion, if such determination is expressly allocated to the Company herein, subject to the following:

(i) Except as otherwise determined by the Committee, if, on such date, the Stock is listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be the closing price of a share of Stock as quoted on the New York Stock Exchange or such other national or regional securities exchange or market system constituting the primary market for the Stock, as reported in *The Wall Street Journal* or such other source as the Company deems reliable. If the relevant date does not fall on a day on which the Stock has traded on such securities exchange or market system, the date on which the Fair Market Value shall be established shall be the last day on which the Stock was so traded prior to the relevant date, or such other appropriate day as shall be determined by the Committee, in its discretion.

(ii) Notwithstanding the foregoing, the Committee may, in its discretion, determine the Fair Market Value on the basis of the opening, closing, high, low or average sale price of a share of Stock or the actual sale price of a share of Stock received by a Participant, on such date, the preceding trading day, the next succeeding trading day or an average determined over a period of trading days. The Committee may vary its method of determination of the Fair Market Value as provided in this Section for different purposes under the Plan.

(iii) If, on such date, the Stock is not listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be as determined by the Committee in good faith without regard to any restriction other than a restriction which, by its terms, will never lapse.

(q) " ***Incentive Stock Option*** " means an Option intended to be (as set forth in the Award Agreement) and which qualifies as an incentive stock option within the meaning of Section 422(b) of the Code.

(r) "***Insider***" means an Officer, a Director or any other person whose transactions in Stock are subject to Section 16 of the Exchange Act.

(s) ***"Net-Exercise"*** means a procedure by which the Participant will be issued a number of shares of Stock determined in accordance with the following formula:

X = Y(A-B)/A, where
X = the number of shares of Stock to be issued to the Participant upon exercise of the Option;
Y = the total number of shares with respect to which the Participant has elected to exercise the Option;
A = the Fair Market Value of one (1) share of Stock;
B = the exercise price per share (as defined in the Participant's Award Agreement).

(t) "***Nonemployee Director***" means a Director who is not an Employee.

(u) "***Nonemployee Director Award***" means an Award granted to a Nonemployee Director pursuant to Section 7 of the Plan.

(v) "***Nonstatutory Stock Option***" means an Option not intended to be (as set forth in the Award Agreement) an incentive stock option within the meaning of Section 422(b) of the Code.

(w) "***Officer***" means any person designated by the Board as an officer of the Company.

(x) "***Option***" means the right to purchase Stock at a stated price for a specified period of time granted to a Participant pursuant to Section 6 or Section 7 of the Plan. An Option may be either an Incentive Stock Option or a Nonstatutory Stock Option.

(y) ***"Option Expiration Date"*** means the date of expiration of the Option's term as set forth in the Award Agreement.

(z) "***Parent Corporation***" means any present or future "parent corporation" of the Company, as defined in Section 424(e) of the Code.

(aa) "***Participant***" means any eligible person who has been granted one or more Awards.

(bb) "***Participating Company***" means the Company or any Parent Corporation, Subsidiary Corporation or Affiliate.

(cc) "***Participating Company Group***" means, at any point in time, all entities collectively which are then Participating Companies.

(dd) "***Performance Award***" means an Award of Performance Shares or Performance Units.

(ee) "***Performance Award Formula***" means, for any Performance Award, a formula or table established by the Committee pursuant to Section 10.3 of the Plan which provides the basis for computing the value of a Performance Award at one or more threshold levels of attainment of the applicable Performance Goal(s) measured as of the end of the applicable Performance Period.

(ff) "***Performance Goal***" means a performance goal established by the Committee pursuant to Section 10.3 of the Plan.

(gg) "***Performance Period***" means a period established by the Committee pursuant to Section 10.3 of the Plan at the end of which one or more Performance Goals are to be measured.

(hh) "***Performance Share***" means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Share, as determined by the Committee, based on performance.

(ii) "***Performance Unit***" means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Unit, as determined by the Committee, based upon performance.

(jj) "***Restricted Stock Award***" means an Award of Restricted Stock.

(kk) "***Restricted Stock Unit"*** or "***Stock Unit***" means a bookkeeping entry representing a right granted to a Participant pursuant to Section 11 or Section 12 of the Plan, respectively, to receive a share of Stock on a date determined in accordance with the provisions of Section 11 or Section 12, as applicable, and the Participant's Award Agreement.

(ll) "***Restriction Period***" means the period established in accordance with Section 9.4 of the Plan during which shares subject to a Restricted Stock Award are subject to Vesting Conditions.

(mm) ***"Retirement"*** means termination as an Employee of a Participating Company at age 55 or older, provided that the Participant was an Employee for at least five consecutive years prior to the date of such termination.

(nn) "***Rule 16b-3***" means Rule 16b-3 under the Exchange Act, as amended from time to time, or any successor rule or regulation.

(oo) " ***SAR*** " or " ***Stock Appreciation Right*** " means a bookkeeping entry representing, for each share of Stock subject to such SAR, a right granted to a Participant pursuant to Section 8 of the Plan to receive payment in any combination of shares of Stock or cash of an amount equal to the excess, if any, of the Fair Market Value of a share of Stock on the date of exercise of the SAR over the exercise price.

(pp) " ***Section 162(m)*** " means Section 162(m) of the Code.

(qq) " ***Section 409A Change in Control*** " means a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation," within the meaning of Section 409A of the Code, as such definition applies to the Company.

(rr) " ***Securities Act*** " means the Securities Act of 1933, as amended.

(ss) " ***Separation from Service*** " means a Participant's "separation from service," within the meaning of Section 409A of the Internal Revenue Code.

(tt) " ***Service*** " means a Participant's employment or service with the Participating Company Group, whether in the capacity of an Employee, a Director or a Consultant. A Participant's Service shall not be deemed to have terminated merely because of a change in the capacity in which the Participant renders such Service or a change in the Participating Company for which the Participant renders such Service, provided that there is no interruption or termination of the Participant's Service. Furthermore, a Participant's Service shall not be deemed to have terminated if the Participant takes any military leave, sick leave, or other bona fide leave of absence approved by the Company. However, if any such leave taken by a Participant exceeds ninety (90) days, then on the one hundred eighty-first (181st) day following the commencement of such leave any Incentive Stock Option held by the Participant shall cease to be treated as an Incentive Stock Option and instead shall be treated thereafter as a Nonstatutory Stock Option, unless the Participant's right to return to Service with the Participating Company Group is guaranteed by statute or contract. Notwithstanding the foregoing, unless otherwise designated by the Company or required by law, a leave of absence shall not be treated as Service for purposes of determining vesting under the Participant's Award Agreement. A Participant's Service shall be deemed to have terminated either upon an actual termination of Service or upon the entity for which the Participant performs Service ceasing to be a Participating Company. Subject to the foregoing, the Company, in its discretion, shall determine whether the Participant's Service has terminated and the effective date of such termination.

(uu) " ***Stock*** " means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(vv) " ***Stock-Based Awards*** " means any award that is valued in whole or in part by reference to, or is otherwise based on, the Stock, including dividends on the Stock, but not limited to those Awards described in Sections 6 through 12 of the Plan.

(ww) " ***Subsidiary Corporation*** " means any present or future "subsidiary corporation" of the Company, as defined in Section 424(f) of the Code.

(xx) " ***Ten Percent Owner*** " means a Participant who, at the time an Option is granted to the Participant, owns stock possessing more than ten percent (10%) of the total combined voting power of all classes of stock of a Participating Company (other than an Affiliate) within the meaning of Section 422(b)(6) of the Code.

(yy) " ***Vesting Conditions*** " mean those conditions established in accordance with Section 9.4 or Section 11.2 of the Plan prior to the satisfaction of which shares subject to a Restricted Stock Award or Restricted Stock Unit Award, respectively, remain subject to forfeiture or a repurchase option in favor of the Company upon the Participant's termination of Service.

2.2 **Construction.** Captions and titles contained herein are for convenience only and shall not affect the meaning or interpretation of any provision of the Plan. Except when otherwise indicated by the context, the singular shall include the plural and the plural shall include the singular. Use of the term "or" is not intended to be exclusive, unless the context clearly requires otherwise.

3. **ADMINISTRATION .**

3.1 **Administration by the Committee.** The Plan shall be administered by the Committee. All questions of interpretation of the Plan or of any Award shall be determined by the Committee, and such determinations shall be final and binding upon all persons having an interest in the Plan or such Award.

3.2 **Authority of Officers.** Any Officer shall have the authority to act on behalf of the Company with respect to any matter, right, obligation, determination or election which is the responsibility of or which is allocated to the Company herein, provided the Officer has apparent authority with respect to such matter, right, obligation, determination or election. In addition, to the extent specified in a resolution adopted by the Board, the Chief Executive Officer of the Company shall have the authority to grant Awards to an Employee who is not an Insider and who is receiving a salary below the level which requires approval by the Committee; provided that the terms of such Awards conform to guidelines established by the Committee and provided further that at the time of making such Awards the Chief Executive Officer also is a Director.

3.3 **Administration with Respect to Insiders.** With respect to participation by Insiders in the Plan, at any time that any class of equity security of the Company is registered pursuant to Section 12 of the Exchange Act, the Plan shall be administered in compliance with the requirements, if any, of Rule 16b-3.

3.4 **Committee Complying with Section 162(m).** While the Company is a "publicly held corporation" within the meaning of Section 162(m), the Board may establish a Committee of "outside directors" within the meaning of Section 162(m) to approve the grant of any Award which might reasonably be anticipated to result in the payment of employee remuneration that would otherwise exceed the limit on employee remuneration deductible for income tax purposes pursuant to Section 162(m).

3.5 **Powers of the Committee .** In addition to any other powers set forth in the Plan and subject to the provisions of the Plan, the Committee shall have the full and final power and authority, in its discretion:

(a) to determine the persons to whom, and the time or times at which, Awards shall be granted and the number of shares of Stock or units to be subject to each Award based on the recommendation of the Chief Executive Officer of the Company (except that Awards to the Chief Executive Officer shall be based on the recommendation of the independent members of the Board in compliance with applicable stock exchange rules and Awards to Nonemployee Directors shall be granted automatically pursuant to Section 7 of the Plan);

(b) to determine the type of Award granted and to designate Options as Incentive Stock Options or Nonstatutory Stock Options;

(c) to determine the Fair Market Value of shares of Stock or other property;

(d) to determine the terms, conditions and restrictions applicable to each Award (which need not be identical) and any shares acquired pursuant thereto, including, without limitation, (i) the exercise or purchase price of shares purchased pursuant to any Award, (ii) the method of payment for shares purchased pursuant to any Award, (iii) the method for satisfaction of any tax withholding obligation arising in connection with Award, including by the withholding or delivery of shares of Stock, (iv) the timing, terms and conditions of the exercisability or vesting of any Award or any shares acquired pursuant thereto, (v) the Performance Award Formula and Performance Goals applicable to any Award and the extent to which such Performance Goals have been attained, (vi) the time of the expiration of any Award, (vii) the effect of the Participant's termination of Service on any of the foregoing, and (viii) all other terms, conditions and restrictions applicable to any Award or shares acquired pursuant thereto not inconsistent with the terms of the Plan;

(e) to determine whether an Award will be settled in shares of Stock, cash, or in any combination thereof;

(f) to approve one or more forms of Award Agreement;

(g) to amend, modify, extend, cancel or renew any Award or to waive any restrictions or conditions applicable to any Award or any shares acquired pursuant thereto;

(h) to accelerate, continue, extend or defer the exercisability or vesting of any Award or any shares acquired pursuant thereto, including with respect to the period following a Participant's termination of Service;

(i) without the consent of the affected Participant and notwithstanding the provisions of any Award Agreement to the contrary, to unilaterally substitute at any time a Stock Appreciation Right providing for settlement solely in shares of Stock in place of any outstanding Option, provided that such Stock Appreciation Right covers the same number of shares of Stock and provides for the same exercise price (subject in each case to adjustment in accordance with Section 4.2 ) as the replaced Option and otherwise provides substantially equivalent terms and conditions as the replaced Option, as determined by the Committee;

(j) to prescribe, amend or rescind rules, guidelines and policies relating to the Plan, or to adopt sub-plans or supplements to, or alternative versions of, the Plan, including, without limitation, as the Committee deems necessary or desirable to comply with the laws or regulations of or to accommodate the tax policy, accounting principles or custom of, foreign jurisdictions whose citizens may be granted Awards;

(k) to correct any defect, supply any omission or reconcile any inconsistency in the Plan or any Award Agreement and to make all other determinations and take such other actions with respect to the Plan or any Award as the Committee may deem advisable to the extent not inconsistent with the provisions of the Plan or applicable law; and

(l) to delegate to the Chief Executive Officer or the Senior Vice President of Human Resources the authority with respect to ministerial matters regarding the Plan and Awards made under the Plan.

3.6 **Option or SAR Repricing/Buyout.** Notwithstanding anything to the contrary set forth in the Plan, without the affirmative vote of holders of a majority of the shares of Stock cast in person or by proxy at a meeting of the shareholders of the Company at which a quorum representing a majority of all outstanding shares of Stock is present or represented by proxy, the Company shall not approve a program providing for any of the following: (a) the cancellation of outstanding Options or SARs and the grant in substitution therefore of new Options or SARs having a lower exercise price, (b) the amendment of outstanding Options or SARs to reduce the exercise price thereof or (c) the purchase of outstanding unexercised Options or SARs by the Company whether by cash payment or otherwise. This paragraph shall not be construed to apply to "issuing or assuming a stock option in a transaction to which section 424(a) applies," within the meaning of Section 424 of the Code.

3.7 **Indemnification.** In addition to such other rights of indemnification as they may have as members of the Board or the Committee or as officers or employees of the Participating Company Group, members of the Board or the Committee and any officers or employees of the Participating Company Group to whom authority to act for the Board, the Committee or the Company is delegated shall be indemnified by the Company against all reasonable expenses, including attorneys' fees, actually and necessarily incurred in connection with the

defense of any action, suit or proceeding, or in connection with any appeal therein, to which they or any of them may be a party by reason of any action taken or failure to act under or in connection with the Plan, or any right granted hereunder, and against all amounts paid by them in settlement thereof (provided such settlement is approved by independent legal counsel selected by the Company) or paid by them in satisfaction of a judgment in any such action, suit or proceeding, except in relation to matters as to which it shall be adjudged in such action, suit or proceeding that such person is liable for gross negligence, bad faith or intentional misconduct in duties; provided, however, that within sixty (60) days after the institution of such action, suit or proceeding, such person shall offer to the Company, in writing, the opportunity at its own expense to handle and defend the same.

4. **SHARES SUBJECT TO PLAN .**

4.1 **Maximum Number of Shares Issuable.** Subject to adjustment as provided in Section 4.2 and subject to Section 409A of the Code, the maximum aggregate number of shares of Stock that may be issued under the Plan shall be twelve million (12,000,000) and shall consist of authorized but unissued or reacquired shares of Stock or any combination thereof. If an outstanding Award for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of Stock acquired pursuant to an Award subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of Stock allocable to the terminated portion of such Award or such forfeited or repurchased shares of Stock shall again be available for issuance under the Plan. Shares of Stock shall not be deemed to have been issued pursuant to the Plan with respect to any portion of an Award that is settled in cash (other than in the case of Options or SARs, in which case shares of Stock having a Fair Market Value equal to the cash delivered shall be deemed issued pursuant to the Plan). In addition, shares of Stock shall not be deemed to have been issued pursuant to the Plan to the extent such shares are withheld or reacquired by the Company in satisfaction of tax withholding obligations pursuant to Section 16.2 (other than in the case of such shares withheld in connection with the exercise of Options or SARs, which shall be deemed to be issued pursuant to the Plan). Upon the exercise of an SAR, the number of shares available for issuance under the Plan shall be reduced by the gross number of shares for which the SAR is exercised. If the exercise price of an Option is paid by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant, or by means of a Net-Exercise, the number of shares available for issuance under the Plan shall be reduced by the gross number of shares for which the Option is exercised.

4.2 **Adjustments for Changes in Capital Structure .** Subject to any required action by the shareholders of the Company, in the event of any change in the Stock effected without receipt of consideration by the Company, whether through merger, consolidation, reorganization, reincorporation, recapitalization, reclassification, stock dividend, stock split, reverse stock split, split-up, split-off, spin-off, combination of shares, exchange of shares, or similar change in the capital structure of the Company, or in the event of payment of a dividend or distribution to the shareholders of the Company in a form other than Stock (excepting normal cash dividends) that has a material effect on the Fair Market Value of shares of Stock, appropriate adjustments shall be made in the number and kind of shares subject to the Plan and to any outstanding Awards, in the Award limits set forth in Section 5.4 , in the Nonemployee Director Awards to be granted automatically pursuant to Section 7, and in the exercise or purchase price per share under any outstanding Award in order to prevent dilution or enlargement of Participants' rights under the Plan. For purposes of the foregoing, conversion of any convertible securities of the Company shall not be treated as "effected without receipt of consideration by the Company." Any fractional share resulting from an adjustment pursuant to this Section 4.2 shall be rounded down to the nearest whole number. The Committee in its sole discretion, may also make such adjustments in the terms of any Award to reflect, or related to, such changes in the capital structure of the Company or distributions as it deems appropriate, including modification of Performance Goals, Performance Award Formulas and Performance Periods. The adjustments determined by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

5. **ELIGIBILITY AND AWARD LIMITATIONS .**

5.1 **Persons Eligible for Awards.** Awards may be granted only to Employees, Consultants and Directors. For purposes of the foregoing sentence, "Employees," "Consultants" and "Directors" shall include prospective Employees, prospective Consultants and prospective Directors to whom Awards are granted in connection with written offers of an employment or other service relationship with the Participating Company Group; provided, however, that no Stock subject to any such Award shall vest, become exercisable or be issued prior to the date on which such person commences Service. A Nonemployee Director Award may be granted only to a person who, at the time of grant, is a Nonemployee Director.

5.2 **Participation.** Awards other than Nonemployee Director Awards are granted solely at the discretion of the Committee. Eligible persons may be granted more than one Award. However , excepting Nonemployee Director Awards, eligibility in accordance with this Section shall not entitle any person to be granted an Award, or, having been granted an Award, to be granted an additional Award.

5.3 **Incentive Stock Option Limitations.**

(a) ***Persons Eligible.*** An Incentive Stock Option may be granted only to a person who, on the effective date of grant, is an Employee of the Company, a Parent Corporation or a Subsidiary Corporation (each being an " ***ISO-Qualifying Corporation*** "). Any person who is not an Employee of an ISO-Qualifying Corporation on the effective date of the grant of an Option to such person may be granted only a Nonstatutory Stock Option. An Incentive Stock Option granted to a prospective Employee upon the condition that such person become an Employee of an ISO-Qualifying Corporation shall be deemed granted effective on the date such person commences Service with an ISO-Qualifying Corporation, with an exercise price determined as of such date in accordance with Section 6.1 .

(b) ***Fair Market Value Limitation.*** To the extent that options designated as Incentive Stock Options (granted under all stock option plans of the Participating Company Group, including the Plan) become exercisable by a Participant for the first time during any calendar year for stock having a Fair Market Value greater than One Hundred Thousand Dollars ($100,000), the portion of such options which exceeds such amount shall be treated as Nonstatutory Stock Options. For purposes of this Section, options designated as Incentive Stock

Options shall be taken into account in the order in which they were granted, and the Fair Market Value of stock shall be determined as of the time the option with respect to such stock is granted. If the Code is amended to provide for a limitation different from that set forth in this Section, such different limitation shall be deemed incorporated herein effective as of the date and with respect to such Options as required or permitted by such amendment to the Code. If an Option is treated as an Incentive Stock Option in part and as a Nonstatutory Stock Option in part by reason of the limitation set forth in this Section, the Participant may designate which portion of such Option the Participant is exercising. In the absence of such designation, the Participant shall be deemed to have exercised the Incentive Stock Option portion of the Option first. Upon exercise, shares issued pursuant to each such portion shall be separately identified.

5.4 **Award Limits.**

(a) ***Maximum Number of Shares Issuable Pursuant to Incentive Stock Options.*** Subject to adjustment as provided in Section 4.2 , the maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to the exercise of Incentive Stock Options shall not exceed twelve million (12,000,000) shares. The maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to all Awards other than Incentive Stock Options shall be the number of shares determined in accordance with Section 4.1 , subject to adjustment as provided in Section 4.2 and further subject to the limitation set forth in Section 5.4(b) below.

(b) ***Aggregate Limit on Full Value Awards.*** Subject to adjustment as provided in Section 4.2 , in no event shall more than twelve million (12,000,000) shares in the aggregate be issued under the Plan pursuant to the exercise or settlement of Restricted Stock Awards, Restricted Stock Unit Awards and Performance Awards ("Full Value Awards"). Except with respect to a maximum of five percent (5%) of the shares of Stock authorized in this Section 5.4(b), any Full Value Awards which vest on the basis of the Participant's continued Service shall not provide for vesting which is any more rapid than annual pro rata vesting over a three (3) year period and any Full Value Awards which vest upon the attainment of Performance Goals shall provide for a Performance Period of at least twelve (12) months.

(c) ***Section 162(m) Award Limits.*** The following limits shall apply to the grant of any Award if, at the time of grant, the Company is a "publicly held corporation" within the meaning of Section 162(m).

(i) **Options and SARs.** Subject to adjustment as provided in Section 4.2 , no Employee shall be granted within any fiscal year of the Company one or more Options or Freestanding SARs which in the aggregate are for more than 400,000 shares of Stock reserved for issuance under the Plan.

(ii) **Restricted Stock and Restricted Stock Unit Awards.** Subject to adjustment as provided in Section 4.2 , no Employee shall be granted within any fiscal year of the Company one or more Restricted Stock Awards or Restricted Stock Unit Awards, subject to Vesting Conditions based on the attainment of Performance Goals, for more than 400,000 shares of Stock reserved for issuance under the Plan.

(iii) **Performance Awards.** Subject to adjustment as provided in Section 4.2 , no Employee shall be granted (1) one or more awards of Performance Shares which could result in such Employee receiving more than 400,000 shares of Stock reserved for issuance under the Plan for each full fiscal year of the Company contained in the Performance Period for such Award, and (2) one or more awards of Performance Units which could result in such Employee receiving more than five million dollars ($5 million) for each full fiscal year of the Company contained in the Performance Period for such Award, with such amount to be pro-rated for Performance Periods of less than one full fiscal year.

6. **TERMS AND CONDITIONS OF OPTIONS .**

Options shall be evidenced by Award Agreements specifying the number of shares of Stock covered thereby, in such form as the Committee shall from time to time establish. No Option or purported Option shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Options may incorporate all or any of the terms of the Plan by reference and , except as otherwise set forth in Section 7 with respect to Nonemployee Director Options, if any, shall comply with and be subject to the following terms and conditions:

6.1 **Exercise Price .** The exercise price for each Option shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the Option and (b) no Incentive Stock Option granted to a Ten Percent Owner shall have an exercise price per share less than one hundred ten percent (110%) of the Fair Market Value of a share of Stock on the effective date of grant of the Option. Notwithstanding the foregoing, an Option (whether an Incentive Stock Option or a Nonstatutory Stock Option) may be granted with an exercise price lower than the minimum exercise price set forth above if such Option is granted pursuant to an assumption or substitution for another option in a manner qualifying under the provisions of Section 424(a) of the Code.

6.2 **Exercisability and Term of Options .** Options shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such Option; provided, however, that (a) no Option shall be exercisable after the expiration of ten (10) years after the effective date of grant of such Option, (b) no Incentive Stock Option granted to a Ten Percent Owner shall be exercisable after the expiration of five (5) years after the effective date of grant of such Option, and (c) no Option granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service. Subject to the foregoing, unless otherwise specified by the Committee in the grant of an Option, any Option granted hereunder shall terminate ten (10) years after the effective date of grant of the Option, unless earlier terminated in accordance with its provisions.

6.3 **Payment of Exercise Price.**

(a) ***Forms of Consideration Authorized.*** Except as otherwise provided below, payment of the exercise price for the number of shares of Stock being purchased pursuant to any Option shall be made (i) in cash, by check or in cash equivalent, (ii) by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant having a Fair Market Value not less than the exercise price, (iii) by delivery of a properly executed notice of exercise together with irrevocable instructions to a broker providing for the assignment to the Company of the proceeds of a sale or loan with respect to some or all of the shares being acquired upon the exercise of the Option (including, without limitation, through an exercise complying with the provisions of Regulation T as promulgated from time to time by the Board of Governors of the Federal Reserve System) (a " ***Cashless Exercise*** "), (iv) by delivery of a properly executed notice of exercise electing a Net-Exercise, (v) by such other consideration as may be approved by the Committee from time to time to the extent permitted by applicable law, or (vi) by any combination thereof. The Committee may at any time or from time to time grant Options which do not permit all of the foregoing forms of consideration to be used in payment of the exercise price or which otherwise restrict one or more forms of consideration.

(b) ***Limitations on Forms of Consideration.***

(i) **Tender of Stock.** Notwithstanding the foregoing, an Option may not be exercised by tender to the Company, or attestation to the ownership, of shares of Stock to the extent such tender or attestation would constitute a violation of the provisions of any law, regulation or agreement restricting the redemption of the Company's stock.

(ii) **Cashless Exercise.** The Company reserves, at any and all times, the right, in the Company's sole and absolute discretion, to establish, decline to approve or terminate any program or procedures for the exercise of Options by means of a Cashless Exercise, including with respect to one or more Participants specified by the Company notwithstanding that such program or procedures may be available to other Participants.

6.4 **Effect of Termination of Service.**

(a) ***Option Exercisability .*** Subject to earlier termination of the Option as otherwise provided herein and unless otherwise provided by the Committee, an Option shall be exercisable after a Participant's termination of Service only during the applicable time periods provided in the Award Agreement.

(b) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an Option within the applicable time periods is prevented by the provisions of Section 14.1 below, the Option shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the Option is exercisable, but in any event no later than the Option Expiration Date.

(c) ***Extension if Participant Subject to Section 16(b*** **).** Notwithstanding the foregoing, if a sale within the applicable time periods of shares acquired upon the exercise of the Option would subject the Participant to suit under Section 16(b) of the Exchange Act, the Option shall remain exercisable until the earliest to occur of (i) the tenth (10th) day following the date on which a sale of such shares by the Participant would no longer be subject to such suit, (ii) the one hundred and ninetieth (190th) day after the Participant's termination of Service, or (iii) the Option Expiration Date.

6.5 **Transferability of Options.** During the lifetime of the Participant, an Option shall be exercisable only by the Participant or the Participant's guardian or legal representative. Prior to the issuance of shares of Stock upon the exercise of an Option, the Option shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. Notwithstanding the foregoing, to the extent permitted by the Committee, in its discretion, and set forth in the Award Agreement evidencing such Option, a Nonstatutory Stock Option shall be assignable or transferable subject to the applicable limitations, if any, described in the General Instructions to Form S-8 Registration Statement under the Securities Act.

7. **TERMS AND CONDITIONS OF NONEMPLOYEE DIRECTOR AWARDS .**

Nonemployee Director Awards granted under this Plan shall be automatic and non-discretionary and shall comply with and be subject to the terms and conditions set forth in this Section 7.

For purposes of this Section 7 as amended on December 15, 2010, the grant date for all Nonemployee Director awards to be made under this Section 7 shall be the date on which the independent inspector of election certifies the results of the annual election of directors by shareholders of PG&E Corporation; provided, however, that in extraordinary circumstances, the grant shall be delayed until the first business day of the next open trading window period following certification of the director election results, as determined by the General Counsel of PG&E Corporation (the "Grant Date")

Grants made pursuant to this Section 7, but prior to December 15, 2010, shall be subject to the terms of the Plan in effect at the time of grant.

7.1 **Grant of Restricted Stock Unit.**

(a) ***Timing and Amount of Grant .*** Each person who is a Nonemployee Director on the Grant Date shall receive a grant of Restricted Stock Units with the number of Restricted Stock Units determined by dividing $105,000 by the Fair Market Value of the Stock on

the Grant Date (rounded down to the nearest whole Restricted Stock Unit). The Restricted Stock Units awarded to a Nonemployee Director shall be credited to the director's Restricted Stock Unit account. Each Restricted Stock Unit awarded to a Nonemployee Director in accordance with this Section 7.1(a) shall be deemed to be equal to one (1) (or fraction thereof) share of Stock on the Grant Date, and the value of the Restricted Stock Unit shall thereafter fluctuate in value in accordance with the Fair Market Value of the Stock. No person shall receive more than one grant of Restricted Stock Units pursuant to this Section 7.1(a) during any calendar year.

(b) ***Dividend Rights*** . Each Nonemployee Director's Restricted Stock Unit account shall be credited quarterly on each dividend payment date with additional shares of Restricted Stock Units (including fractions computed to three decimal places) determined by dividing (1) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the account by (2) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award.

(c) ***Settlement of Restricted Stock Units*** . Restricted Stock Units credited to a Nonemployee Director's Restricted Stock Unit account shall be settled in a lump sum by the issuance of an equal number of shares of Stock, rounded down to the nearest whole share, upon the earliest of (i) the first anniversary of the Grant Date (normal vesting date), (ii) the Nonemployee Director's death, (iii) the Nonemployee Director's Disability (within the meaning of Section 409A of the Code), (iv) a Change in Control that also constitutes a Section 409A Change in Control, or (v) the Nonemployee Director's Separation from Service following a Change in Control. However, commencing with Restricted Stock Units having a Grant Date in 2013, a Nonemployee Director may irrevocably elect, no later than December 31 of the calendar year prior to the Grant Date of the Restricted Stock Units (or such later time permitted by Section 409A) to have the Nonemployee Director's Restricted Stock Unit account settled in (1) a series of 10 approximately equal annual installments (which shall be separate payments for purposes of Section 409A) commencing in January of any year following the normal vesting date, or (2) a lump sum in January of any future year following the normal vesting date. In the event that the Nonemployee Director elects settlement of the Restricted Stock Units in accordance with the immediately preceding sentence, the Restricted Stock Units shall be earlier settled in a lump sum upon the occurrence of any of the events set forth in Section 7.1(c)(ii) through 7.1(c)(v) prior to the elected settlement date (or commencement thereof in the case of settlement in 10 equal annual installments). In the event that a Nonemployee Director elects to have the Nonemployee Director's Restricted Stock Unit account settled in a series of 10 approximately equal annual installments commencing in January of any year following the normal vesting date and one of the events set forth in Section 7.1(c)(ii) through 7.1(c)(v) occurs after commencement of such installments but prior to full settlement of the Nonemployee Director's Restricted Stock Units, then any remaining unsettled Restricted Stock Units will be settled in a lump sum upon the occurrence of the applicable event but only to the extent that such acceleration would not result in the imposition of taxation under Section 409A.

7.2 **Effect of Termination of Service as a Nonemployee Director.**

(a) ***Forfeiture of Award .*** If the Nonemployee Director has a Separation from Service prior to the normal vesting date, other than for the occurrence of any of the distribution events set forth in Section 7.1(c), all Restricted Stock Units credited to the Participant's account shall be forfeited to the Company and from and after the date of such Separation from Service, and the Participant shall cease to have any rights with respect thereto; provided, however, that if the Nonemployee Director Separates from Service due to a pending Disability determination, such forfeiture shall not occur until a finding that such Disability has not occurred.

(b) ***Death or Disability*** . If the Nonemployee Director becomes "disabled," within the meaning of Section 409A of the Code or in the event of the Nonemployee Director's death, all Restricted Stock Units credited to the Nonemployee Director's account shall immediately vest and become payable, in accordance with Section 7.1(c), to the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock Units by reason of the Participant's death) in the form of a number of shares of Stock equal to the number of Restricted Stock Units credited to the Restricted Stock Unit account, rounded down to the nearest whole share.

(c) Notwithstanding the provisions of Section 7.1(c) above, the Board, in its sole discretion, may establish different terms and conditions pertaining to Nonemployee Director Awards.

7.3 **Effect of Change in Control on Nonemployee Director Awards.** Upon the occurrence of a Change in Control, all Restricted Stock Units shall immediately vest but shall not be settled until such time set forth in Section 7.1(c) occurs.

8. **TERMS AND CONDITIONS OF STOCK APPRECIATION RIGHTS .**

Stock Appreciation Rights shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No SAR or purported SAR shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing SARs may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

8.1 **Types of SARs Authorized.** SARs may be granted in tandem with all or any portion of a related Option (a " ***Tandem SAR*** ") or may be granted independently of any Option (a " ***Freestanding SAR*** "). A Tandem SAR may be granted either concurrently with the grant of the related Option or at any time thereafter prior to the complete exercise, termination, expiration or cancellation of such related Option.

8.2 **Exercise Price.** The exercise price for each SAR shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share subject to a Tandem SAR shall be the exercise price per share under the related Option and (b) the exercise price per share subject to a Freestanding SAR shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the SAR.

8.3 **Exercisability and Term of SARs.**

(a) ***Tandem SARs.*** Tandem SARs shall be exercisable only at the time and to the extent, and only to the extent, that the related Option is exercisable, subject to such provisions as the Committee may specify where the Tandem SAR is granted with respect to less than the full number of shares of Stock subject to the related Option.

(b) ***Freestanding SARs.*** Freestanding SARs shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such SAR; provided, however, that no Freestanding SAR shall be exercisable after the expiration of ten (10) years after the effective date of grant of such SAR.

8.4 **Deemed Exercise of SARs.** If, on the date on which an SAR would otherwise terminate or expire, the SAR by its terms remains exercisable immediately prior to such termination or expiration and, if so exercised, would result in a payment to the holder of such SAR, then any portion of such SAR which has not previously been exercised shall automatically be deemed to be exercised as of such date with respect to such portion.

8.5 **Effect of Termination of Service.** Subject to earlier termination of the SAR as otherwise provided herein and unless otherwise provided by the Committee in the grant of an SAR and set forth in the Award Agreement, an SAR shall be exercisable after a Participant's termination of Service only as provided in the Award Agreement.

8.6 **Nontransferability of SARs.** During the lifetime of the Participant, an SAR shall be exercisable only by the Participant or the Participant's guardian or legal representative. Prior to the exercise of an SAR, the SAR shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution.

9. **TERMS AND CONDITIONS OF RESTRICTED STOCK AWARDS .**

Restricted Stock Awards shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Award or purported Restricted Stock Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

9.1 **Types of Restricted Stock Awards Authorized.** Restricted Stock Awards may or may not require the payment of cash compensation for the stock. Restricted Stock Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 . If either the grant of a Restricted Stock Award or the lapsing of the Restriction Period is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) .

9.2 **Purchase Price.** The purchase price, if any, for shares of Stock issuable under each Restricted Stock Award and the means of payment shall be established by the Committee in its discretion.

9.3 **Purchase Period.** A Restricted Stock Award requiring the payment of cash consideration shall be exercisable within a period established by the Committee; provided, however, that no Restricted Stock Award granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service.

9.4 **Vesting and Restrictions on Transfer.** Shares issued pursuant to any Restricted Stock Award may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4 , as shall be established by the Committee and set forth in the Award Agreement evidencing such Award. During any Restriction Period in which shares acquired pursuant to a Restricted Stock Award remain subject to Vesting Conditions, such shares may not be sold, exchanged, transferred, pledged, assigned or otherwise disposed of other than as provided in the Award Agreement or as provided in Section 9.7 . Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

9.5 **Voting Rights, Dividends and Distributions.** Except as provided in this Section, Section 9.4 and any Award Agreement, during the Restriction Period applicable to shares subject to a Restricted Stock Award, the Participant shall have all of the rights of a shareholder of the Company holding shares of Stock, including the right to vote such shares and to receive all dividends and other distributions paid with respect to such shares. However, in the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant is entitled by reason of the Participant's Restricted Stock Award shall be immediately subject to the same Vesting Conditions as the shares subject to the Restricted Stock Award with respect to which such dividends or distributions were paid or adjustments were made.

9.6 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any shares acquired by the Participant pursuant to a Restricted

Stock Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service in exchange for the payment of the purchase price, if any, paid by the Participant. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company.

9.7 **Nontransferability of Restricted Stock Award Rights.** Prior to the issuance of shares of Stock pursuant to a Restricted Stock Award, rights to acquire such shares shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or the laws of descent and distribution. All rights with respect to a Restricted Stock Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

10. **TERMS AND CONDITIONS OF PERFORMANCE AWARDS .**

Performance Awards shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No Performance Award or purported Performance Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Performance Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

10.1 **Types of Performance Awards Authorized.** Performance Awards may be in the form of either Performance Shares or Performance Units. Each Award Agreement evidencing a Performance Award shall specify the number of Performance Shares or Performance Units subject thereto, the Performance Award Formula, the Performance Goal(s) and Performance Period applicable to the Award, and the other terms, conditions and restrictions of the Award.

10.2 **Initial Value of Performance Shares and Performance Units.** Unless otherwise provided by the Committee in granting a Performance Award, each Performance Share shall have an initial value equal to the Fair Market Value of one (1) share of Stock, subject to adjustment as provided in Section 4.2 , on the effective date of grant of the Performance Share. Each Performance Unit shall have an initial value determined by the Committee. The final value payable to the Participant in settlement of a Performance Award determined on the basis of the applicable Performance Award Formula will depend on the extent to which Performance Goals established by the Committee are attained within the applicable Performance Period established by the Committee.

10.3 **Establishment of Performance Period, Performance Goals and Performance Award Formula.** In granting each Performance Award, the Committee shall establish in writing the applicable Performance Period, Performance Award Formula and one or more Performance Goals which, when measured at the end of the Performance Period, shall determine on the basis of the Performance Award Formula the final value of the Performance Award to be paid to the Participant. To the extent compliance with the requirements under Section 162(m) with respect to "performance-based compensation" is desired, the Committee shall establish the Performance Goal(s) and Performance Award Formula applicable to each Performance Award no later than the earlier of (a) the date ninety (90) days after the commencement of the applicable Performance Period or (b) the date on which 25% of the Performance Period has elapsed, and, in any event, at a time when the outcome of the Performance Goals remains substantially uncertain. Once established, the Performance Goals and Performance Award Formula shall not be changed during the Performance Period. The Company shall notify each Participant granted a Performance Award of the terms of such Award, including the Performance Period, Performance Goal(s) and Performance Award Formula.

10.4 **Measurement of Performance Goals.** Performance Goals shall be established by the Committee on the basis of targets to be attained ( " ***Performance Targets*** " ) with respect to one or more measures of business or financial performance (each, a " ***Performance Measure*** " ), subject to the following:

(a) ***Performance Measures.*** Performance Measures shall be calculated with respect to the Company and/or each Subsidiary Corporation and/or such division or other business unit as may be selected by the Committee. Performance Measures may be based upon one or more of the following objectively defined and non-discretionary business criteria and any other objectively verifiable and non-discretionary adjustments permitted and pre-established by the Committee in accordance with Section 162(m), as determined by the Committee: (i) sales revenue; (ii) gross margin; (iii) operating margin; (iv) operating income; (v) pre-tax profit; (vi) earnings before interest, taxes and depreciation and amortization (EBITDA)/adjusted EBITDA; (vii) net income; (viii) expenses; (ix) the market price of the Stock; (x) earnings per share; (xi) return on shareholder equity or assets; (xii) return on capital; (xiii) return on net assets; (xiv) economic profit or economic value added (EVA); (xv) market share; (xvi) customer satisfaction; (xvii) safety; (xviii) total shareholder return; (xix) earnings; (xx) cash flow; (xxi) revenue; (xxii) profits before interest and taxes; (xxiii) profit/loss; (xxiv) profit margin; (xxv) working capital; (xxvi) price/earnings ratio; (xxvii) debt or debt-to-equity; (xxviii) accounts receivable; (xxix) write-offs; (xxx) cash; (xxxi) assets; (xxxii) liquidity; (xxxiii) earnings from operations; (xxxiv) operational reliability; (xxxv) environmental performance; (xxxvi) funds from operations; (xxxvii) adjusted revenues; (xxxviii) free cash flow; or (xxxix) core earnings.

(b) ***Performance Targets.*** Performance Targets may include a minimum, maximum, target level and intermediate levels of performance, with the final value of a Performance Award determined under the applicable Performance Award Formula by the level attained during the applicable Performance Period. A Performance Target may be stated as an absolute value or as a value determined relative to a standard selected by the Committee.

10.5 **Settlement of Performance Awards.**

(a) ***Determination of Final Value.*** As soon as practicable, but no later than the 15th day of the third month following the completion of the Performance Period applicable to a Performance Award, the Committee shall certify in writing the extent to which the applicable Performance Goals have been attained and the resulting final value of the Award earned by the Participant and to be paid upon its settlement in accordance with the applicable Performance Award Formula.

(b) ***Discretionary Adjustment of Award Formula.*** In its discretion, the Committee may, either at the time it grants a Performance Award or at any time thereafter, provide for the positive or negative adjustment of the Performance Award Formula applicable to a Performance Award that is not intended to constitute "qualified performance based compensation" to a "covered employee" within the meaning of Section 162(m) (a " ***Covered Employee*** " ) to reflect such Participant's individual performance in his or her position with the Company or such other factors as the Committee may determine. With respect to a Performance Award intended to constitute qualified performance-based compensation to a Covered Employee, the Committee shall have the discretion to reduce some or all of the value of the Performance Award that would otherwise be paid to the Covered Employee upon its settlement notwithstanding the attainment of any Performance Goal and the resulting value of the Performance Award determined in accordance with the Performance Award Formula.

(c) ***Payment in Settlement of Performance Awards.*** As soon as practicable following the Committee's determination and certification in accordance with Sections 10.5 (a) and (b) but, in any case, no later than the 15th day of the third month following completion of the Performance Period applicable to a Performance Award, payment shall be made to each eligible Participant (or such Participant's legal representative or other person who acquired the right to receive such payment by reason of the Participant's death) of the final value of the Participant's Performance Award. Payment of such amount shall be made in cash, shares of Stock, or a combination thereof as determined by the Committee.

10.6 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Performance Share Awards until the date of the issuance of such shares, if any (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Performance Share Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which the Performance Shares are settled or forfeited. Such Dividend Equivalents, if any, shall be credited to the Participant in the form of additional whole Performance Shares as of the date of payment of such cash dividends on Stock. The number of additional Performance Shares (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Performance Shares previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Dividend Equivalents may be paid currently or may be accumulated and paid to the extent that Performance Shares become nonforfeitable, as determined by the Committee in accordance with Section 409A of the Code. Settlement of Dividend Equivalents may be made in cash, shares of Stock, or a combination thereof as determined by the Committee, and may be paid on the same basis as settlement of the related Performance Share as provided in Section 10.5 . Dividend Equivalents shall not be paid with respect to Performance Units. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Performance Share Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Performance Share Award, and all such new, substituted or additional securities or other property shall be immediately subject to the same Performance Goals as are applicable to the Award.

10.7 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Performance Award and set forth in the Award Agreement, the effect of a Participant's termination of Service on the Performance Award shall be as follows:

(a) ***Death or Disability.*** If the Participant's Service terminates because of the death or Disability of the Participant before the completion of the Performance Period applicable to the Performance Award, the final value of the Participant's Performance Award shall be determined by the extent to which the applicable Performance Goals have been attained with respect to the entire Performance Period and shall be prorated based on the number of months of the Participant's Service during the Performance Period. Payment shall be made following the end of the Performance Period in any manner permitted by Section 10.5 .

(b) ***Other Termination of Service.*** If the Participant's Service terminates for any reason except death or Disability before the completion of the Performance Period applicable to the Performance Award, such Award shall be forfeited in its entirety; provided, however, that in the event of an involuntary termination of the Participant's Service, the Committee, in its sole discretion, may waive the automatic forfeiture of all or any portion of any such Award.

10.8 **Nontransferability of Performance Awards.** Prior to settlement in accordance with the provisions of the Plan, no Performance Award shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Performance Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

11. **Terms and Conditions of Restricted Stock Unit Awards** .

Restricted Stock Unit Awards shall be evidenced by Award Agreements specifying the number of Restricted Stock Units subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Unit Award or purported Restricted Stock Unit Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Units may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

11.1 **Grant of Restricted Stock Unit Awards.** Restricted Stock Unit Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 . If either the grant of a Restricted Stock Unit Award or the Vesting Conditions with respect to such Award is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through

10.5(a) .

11.2 **Vesting.** Restricted Stock Units may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4 , as shall be established by the Committee and set forth in the Award Agreement evidencing such Award.

11.3 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Restricted Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Restricted Stock Unit Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Restricted Stock Units held by such Participant are settled. Such Dividend Equivalents, if any, shall be paid by crediting the Participant with additional whole Restricted Stock Units as of the date of payment of such cash dividends on Stock. The number of additional Restricted Stock Units (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award, provided that Dividend Equivalents may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Restricted Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award, and all such new, substituted or additional securities or other property shall be immediately subject to the same Vesting Conditions as are applicable to the Award.

11.4 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Unit Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any Restricted Stock Units pursuant to the Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service.

11.5 **Settlement of Restricted Stock Unit Awards.** The Company shall issue to a Participant on the date on which Restricted Stock Units subject to the Participant's Restricted Stock Unit Award vest or on such other date determined by the Committee, in its discretion, and set forth in the Award Agreement one (1) share of Stock (and/or any other new, substituted or additional securities or other property pursuant to an adjustment described in Section 11.3 ) for each Restricted Stock Unit then becoming vested or otherwise to be settled on such date, subject to the withholding of applicable taxes. Notwithstanding the foregoing, if permitted by the Committee and set forth in the Award Agreement, the Participant may elect in accordance with terms specified in the Award Agreement to defer receipt of all or any portion of the shares of Stock or other property otherwise issuable to the Participant pursuant to this Section.

11.6 **Nontransferability of Restricted Stock Unit Awards.** Prior to the issuance of shares of Stock in settlement of a Restricted Stock Unit Award, the Award shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Restricted Stock Unit Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

12. **DEFERRED COMPENSATION AWARDS .**

12.1 **Establishment of Deferred Compensation Award Programs.** This Section 12 shall not be effective unless and until the Committee determines to establish a program pursuant to this Section. The Committee, in its discretion and upon such terms and conditions as it may determine, may establish one or more programs pursuant to the Plan under which:

(a) Participants designated by the Committee who are Insiders or otherwise among a select group of highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to reduce such Participant's compensation otherwise payable in cash (subject to any minimum or maximum reductions imposed by the Committee) and to be granted automatically at such time or times as specified by the Committee one or more Awards of Stock Units with respect to such numbers of shares of Stock as determined in accordance with the rules of the program established by the Committee and having such other terms and conditions as established by the Committee.

(b) Participants designated by the Committee who are Insiders or otherwise among a select group of highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to be granted automatically an Award of Stock Units with respect to such number of shares of Stock and upon such other terms and conditions as established by the Committee in lieu of cash or shares of Stock otherwise issuable to such Participant upon the settlement of a Performance Award or Performance Unit.

12.2 **Terms and Conditions of Deferred Compensation Awards.** Deferred Compensation Awards granted pursuant to this Section 12 shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No such Deferred Compensation Award or purported Deferred Compensation Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Deferred Compensation Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

(a) ***Vesting Conditions*** . Deferred Compensation Awards shall not be subject to any vesting conditions.

(b) ***Terms and Conditions of Stock Units*** .

(i) **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, a Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Stock Units held by such Participant are settled. Such Dividend Equivalents shall be paid by crediting the Participant with additional whole and/or fractional Stock Units as of the date of payment of such cash dividends on Stock. The method of determining the number of additional Stock Units to be so credited shall be specified by the Committee and set forth in the Award Agreement. Such additional Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Stock Units originally subject to the Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award.

(ii) **Settlement of Stock Unit Awards.** A Participant electing to receive an Award of Stock Units pursuant to this Section 12 , shall specify at the time of such election a settlement date with respect to such Award in accordance with rules established by the Committee. The Company shall issue to the Participant upon the earlier of the settlement date elected by the Participant or the date of the Participant's Separation from Service, a number of whole shares of Stock equal to the number of whole Stock Units subject to the Stock Unit Award. Such shares of Stock shall be fully vested, and the Participant shall not be required to pay any additional consideration (other than applicable tax withholding) to acquire such shares. Any fractional Stock Unit subject to the Stock Unit Award shall be settled by the Company by payment in cash of an amount equal to the Fair Market Value as of the payment date of such fractional share.

(iii) **Nontransferability of Stock Unit Awards.** Prior to their settlement in accordance with the provision of the Plan, no Stock Unit Award shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Stock Unit Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

13. **OTHER STOCK-BASED AWARDS** .

In addition to the Awards set forth in Sections 6 through 12 above, the Committee, in its sole discretion, may carry out the purpose of this Plan by awarding Stock-Based Awards as it determines to be in the best interests of the Company and subject to such other terms and conditions as it deems necessary and appropriate.

14. **CHANGE IN CONTROL .**

14.1 **Effect of Change in Control on Options and SARs .** In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror " ), may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Options or SARs or substitute for outstanding Options or SARs substantially equivalent options or SARs covering the Acquiror's stock. Any Options or SARs which are neither assumed or continued by the Acquiror in connection with the Change in Control nor exercised as of the Change in Control shall, contingent on the Change in Control, become fully vested and exercisable immediately prior to the Change in Control. Options and SARs which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting and/or exercisability in connection with the Participant's subsequent termination of Service as the Board may determine.

14.2 **Effect of Change in Control on Other Awards .** In the event of a Change in Control, the Acquiror may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Awards other than Options or SARs or substitute for such Awards substantially equivalent Awards covering the Acquiror's stock. Any such Awards which are neither assumed or continued by the Acquiror in connection with the Change in Control shall, contingent on the Change in Control, become fully vested. Awards which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting or lapse of restrictions in connection with the Participant's subsequent termination of Service as the Board may determine.

14.3 **Nonemployee Director Awards** . Notwithstanding the foregoing, Nonemployee Director Awards shall be subject to the terms of Section 7, and not this Section 14.

15. **COMPLIANCE WITH SECURITIES LAW .**

The grant of Awards and the issuance of shares of Stock pursuant to any Award shall be subject to compliance with all applicable requirements of federal, state and foreign law with respect to such securities and the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, no Award may be exercised or shares issued pursuant to an Award unless (a) a registration statement under the Securities Act shall at the time of such exercise or issuance be in effect with respect to the shares issuable pursuant to the Award or (b) in the opinion of legal counsel to the Company, the shares issuable pursuant to the Award may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares hereunder shall relieve the Company of any liability in respect of the failure to issue or sell such shares as to which such requisite authority shall not have been obtained. As a condition to issuance of any Stock, the Company may require the Participant to satisfy any qualifications that may be necessary or appropriate, to evidence compliance with any applicable law or regulation and to make any

representation or warranty with respect thereto as may be requested by the Company.

16. **TAX WITHHOLDING .**

16.1 **Tax Withholding in General.** The Company shall have the right to deduct from any and all payments made under the Plan, or to require the Participant, through payroll withholding, cash payment or otherwise, including by means of a Cashless Exercise or Net Exercise of an Option, to make adequate provision for, the federal, state, local and foreign taxes, if any, required by law to be withheld by the Participating Company Group with respect to an Award or the shares acquired pursuant thereto. The Company shall have no obligation to deliver shares of Stock, to release shares of Stock from an escrow established pursuant to an Award Agreement, or to make any payment in cash under the Plan until the Participating Company Group's tax withholding obligations have been satisfied by the Participant.

16.2 **Withholding in Shares.** The Company shall have the right, but not the obligation, to deduct from the shares of Stock issuable to a Participant upon the exercise or settlement of an Award, or to accept from the Participant the tender of, a number of whole shares of Stock having a Fair Market Value, as determined by the Company, equal to all or any part of the tax withholding obligations of the Participating Company Group. The Fair Market Value of any shares of Stock withheld or tendered to satisfy any such tax withholding obligations shall not exceed the amount determined by the applicable minimum statutory withholding rates.

17. **AMENDMENT OR TERMINATION OF PLAN .**

The Board or the Committee may amend, suspend or terminate the Plan at any time. However, without the approval of the Company's shareholders, there shall be (a) no increase in the maximum aggregate number of shares of Stock that may be issued under the Plan (except by operation of the provisions of Section 4.2), (b) no change in the class of persons eligible to receive Incentive Stock Options, and (c) no other amendment of the Plan that would require approval of the Company's shareholders under any applicable law, regulation or rule. Notwithstanding the foregoing, only the Board may amend Section 7. No amendment, suspension or termination of the Plan shall affect any then outstanding Award unless expressly provided by the Board or the Committee. In any event, no amendment, suspension or termination of the Plan may adversely affect any then outstanding Award without the consent of the Participant unless necessary to comply with any applicable law, regulation or rule.

18. **MISCELLANEOUS PROVISIONS .**

18.1 **Repurchase Rights .** Shares issued under the Plan may be subject to one or more repurchase options, or other conditions and restrictions as determined by the Committee in its discretion at the time the Award is granted. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

18.2 **Provision of Information.** Each Participant shall be given access to information concerning the Company equivalent to that information generally made available to the Company's common shareholders.

18.3 **Rights as Employee, Consultant or Director.** No person, even though eligible pursuant to Section 5 , shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant. Nothing in the Plan or any Award granted under the Plan shall confer on any Participant a right to remain an Employee, Consultant or Director or interfere with or limit in any way any right of a Participating Company to terminate the Participant's Service at any time. To the extent that an Employee of a Participating Company other than the Company receives an Award under the Plan, that Award shall in no event be understood or interpreted to mean that the Company is the Employee's employer or that the Employee has an employment relationship with the Company.

18.4 **Rights as a Shareholder.** A Participant shall have no rights as a shareholder with respect to any shares covered by an Award until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). No adjustment shall be made for dividends, distributions or other rights for which the record date is prior to the date such shares are issued, except as provided in Section 4.2 or another provision of the Plan.

18.5 **Fractional Shares.** The Company shall not be required to issue fractional shares upon the exercise or settlement of any Award.

18.6 **Severability .** If any one or more of the provisions (or any part thereof) of this Plan shall be held invalid, illegal or unenforceable in any respect, such provision shall be modified so as to make it valid, legal and enforceable, and the validity, legality and enforceability of the remaining provisions (or any part thereof) of the Plan shall not in any way be affected or impaired thereby.

18.7 **Beneficiary Designation.** Subject to local laws and procedures, each Participant may file with the Company a written designation of a beneficiary who is to receive any benefit under the Plan to which the Participant is entitled in the event of such Participant's death before he or she receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. If a married Participant designates a beneficiary other than the Participant's spouse, the effectiveness of such designation may be subject to the consent of the Participant's spouse. If a Participant dies without an effective designation of a beneficiary who is living at the time of the Participant's death, the Company will pay any remaining unpaid benefits to the Participant's legal representative.

18.8 **Unfunded Obligation.** Participants shall have the status of general unsecured creditors of the Company. Any amounts

payable to Participants pursuant to the Plan shall be unfunded and unsecured obligations for all purposes, including, without limitation, Title I of the Employee Retirement Income Security Act of 1974. No Participating Company shall be required to segregate any monies from its general funds, or to create any trusts, or establish any special accounts with respect to such obligations. The Company shall retain at all times beneficial ownership of any investments, including trust investments, which the Company may make to fulfill its payment obligations hereunder. Any investments or the creation or maintenance of any trust or any Participant account shall not create or constitute a trust or fiduciary relationship between the Committee or any Participating Company and a Participant, or otherwise create any vested or beneficial interest in any Participant or the Participant's creditors in any assets of any Participating Company. The Participants shall have no claim against any Participating Company for any changes in the value of any assets which may be invested or reinvested by the Company with respect to the Plan. Each Participating Company shall be responsible for making benefit payments pursuant to the Plan on behalf of its Participants or for reimbursing the Company for the cost of such payments, as determined by the Company in its sole discretion. In the event the respective Participating Company fails to make such payment or reimbursement, a Participant's (or other individual's) sole recourse shall be against the respective Participating Company, and not against the Company. A Participant's acceptance of an Award pursuant to the Plan shall constitute agreement with this provision.

18.9 **Choice of Law.** Except to the extent governed by applicable federal law, the validity, interpretation, construction and performance of the Plan and each Award Agreement shall be governed by the laws of the State of California, without regard to its conflict of law rules.

18.10 **Section 409A of the Code.** Notwithstanding anything to the contrary in the Plan, to the extent any Award payable in connection with a Participant's Separation from Service constitutes deferred compensation subject to (and not exempt from) Section 409A of the Code and (ii) the Participant is deemed at the time of such separation to be a "specified employee" under Section 409A of the Code and the Treasury regulations thereunder, then payment shall not be made or commence until the earlier of (i) six (6)-months after such Separation from Service or (ii) the date of the Participant's death following such Separation from Service; provided, however, that such delay shall only be effected to the extent required to avoid adverse tax treatment to the Participant, including (without limitation) the additional twenty percent (20%) tax for which the Participant would otherwise be liable under Section 409A(a)(1)(B) of the Code in the absence of such delay. Upon the expiration of the applicable delay period, any payment which would have otherwise been paid during that period (whether in a single sum or in installments) in the absence of this paragraph shall be paid to the Participant or the Participant's beneficiary in one lump sum on the first business day immediately following such delay.

**EXHIBIT 12.1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2012** | **2011** | **2010** | **2009** | **2008** |
| **Earnings:** | | | | | |
| Net income | $ 811 | $ 845 | $ 1,121 | $ 1,250 | $ 1,199 |
| Income taxes provision | 298 | 480 | 574 | 482 | 488 |
| Net fixed charges | 891 | 880 | 799 | 817 | 860 |
| **Total Earnings** | **$ 2,000** | **$ 2,205** | **$ 2,494** | **$ 2,549** | **$ 2,547** |
| **Fixed Charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | 834 | 824 | 731 | 754 | $ 794 |
| Interest on capital leases | 9 | 16 | 18 | 19 | 22 |
| AFUDC debt | 48 | 40 | 50 | 44 | 44 |
| **Total Fixed Charges** | **$ 891** | **$ 880** | **$ 799** | **$ 817** | **$ 860** |
| **Ratios of Earnings to Fixed Charges** | **2.24** | **2.51** | **3.12** | **3.12** | **2.96** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

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# EXHIBIT 12.2
# PACIFIC GAS AND ELECTRIC COMPANY
# COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| **Earnings:** | **2012** | **2011** | **2010** | **2009** | **2008** |
| Net income | $ 811 | $ 845 | $ 1,121 | $ 1,250 | $ 1,199 |
| Income taxes provision | 298 | 480 | 574 | 482 | 488 |
| Fixed charges | 891 | 880 | 799 | 817 | 860 |
| **Total Earnings** | **$ 2,000** | **$ 2,205** | **$ 2,494** | **$ 2,549** | **$ 2,547** |
| **Fixed Charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 834 | $ 824 | $ 731 | $ 754 | $ 794 |
| Interest on capital leases | 9 | 16 | 18 | 19 | 22 |
| AFUDC debt | 48 | 40 | 50 | 44 | 44 |
| **Total Fixed Charges** | **$ 891** | **$ 880** | **$ 799** | **$ 817** | **$ 860** |
| **Preferred Stock Dividends:** | | | | | |
| Tax deductible dividends | 9 | 9 | 9 | 9 | 9 |
| Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements | 7 | 8 | 7 | 7 | 7 |
| **Total Preferred Stock Dividends** | **16** | **17** | **16** | **16** | **16** |
| **Total Combined Fixed Charges and Preferred Stock Dividends** | **$ 907** | **$ 897** | **$ 815** | **$ 833** | **$ 876** |
| **Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends** | **2.21** | **2.46** | **3.06** | **3.06** | **2.91** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on tax liabilities.
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**EXHIBIT 12.3**
**PG&E CORPORATION**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 | 2008 |
| **Earnings:** | | | | | |
| Income from continuing operations | $ 830 | $ 858 | $ 1,113 | $ 1,234 | $ 1,198 |
| Income taxes provision | 237 | 440 | 547 | 460 | 425 |
| Fixed charges | 931 | 919 | 850 | 877 | 907 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | (15) | (17) | (16) | (16) | (16) |
| **Total Earnings** | **$ 1,983** | **$ 2,200** | **$ 2,494** | **$ 2,555** | **$ 2,514** |
| **Fixed Charges:** | | | | | |
| Interest and amortization of premiums, discounts and capitalized expenses related to short-term borrowings and long-term debt, net | $ 859 | $ 846 | $ 766 | $ 798 | $ 825 |
| Interest on capital leases | 9 | 16 | 18 | 19 | 22 |
| AFUDC debt | 48 | 40 | 50 | 44 | 44 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | 15 | 17 | 16 | 16 | 16 |
| **Total Fixed Charges** | **$ 931** | **$ 919** | **$ 850** | **$ 877** | **$ 907** |
| **Ratios of Earnings to Fixed Charges** | **$ 2.13** | **$ 2.39** | **2.93** | **2.91** | **2.77** |

Note:
For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, “earnings” represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. “Fixed charges” include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

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## SELECTED FINANCIAL DATA

| (in millions, except per share amounts) | | 2012 | | 2011 | | 2010 | | 2009 | | 2008 [1] |
|---|---|---|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | | | | |
| **For the Year** | | | | | | | | | | |
| Operating revenues | $ | 15,040 | $ | 14,956 | $ | 13,841 | $ | 13,399 | $ | 14,628 |
| Operating income | | 1,693 | | 1,942 | | 2,308 | | 2,299 | | 2,261 |
| Income from continuing operations | | 830 | | 858 | | 1,113 | | 1,234 | | 1,198 |
| Earnings per common share from continuing operations, basic | | 1.92 | | 2.10 | | 2.86 | | 3.25 | | 3.23 |
| Earnings per common share from continuing operations, diluted | | 1.92 | | 2.10 | | 2.82 | | 3.20 | | 3.22 |
| Dividends declared per common share [2] | | 1.82 | | 1.82 | | 1.82 | | 1.68 | | 1.56 |
| **At Year-End** | | | | | | | | | | |
| Common stock price per share | $ | 40.18 | $ | 41.22 | $ | 47.84 | $ | 44.65 | $ | 38.71 |
| Total assets | | 52,449 | | 49,750 | | 46,025 | | 42,945 | | 40,860 |
| Long-term debt (excluding current portion) | | 12,517 | | 11,766 | | 10,906 | | 10,381 | | 9,321 |
| Capital lease obligations (excluding current portion) [3] | | 113 | | 212 | | 248 | | 282 | | 316 |
| Energy recovery bonds (excluding current portion) [4] | | - | | - | | 423 | | 827 | | 1,213 |
| **Pacific Gas and Electric Company For the Year** | | | | | | | | | | |
| Operating revenues | $ | 15,035 | $ | 14,951 | $ | 13,840 | $ | 13,399 | $ | 14,628 |
| Operating income | | 1,695 | | 1,944 | | 2,314 | | 2,302 | | 2,266 |
| Income available for common stock | | 797 | | 831 | | 1,107 | | 1,236 | | 1,185 |
| **At Year-End** | | | | | | | | | | |
| Total assets | | 51,923 | | 49,242 | | 45,679 | | 42,709 | | 40,537 |
| Long-term debt (excluding current portion) | | 12,167 | | 11,417 | | 10,557 | | 10,033 | | 9,041 |
| Capital lease obligations (excluding current portion) [3] | | 113 | | 212 | | 248 | | 282 | | 316 |
| Energy recovery bonds (excluding current portion) [4] | | - | | - | | 423 | | 827 | | 1,213 |

[1] In 2008, PG&E Corporation recorded $154 million in income from discontinued operations related to losses incurred and synthetic fuel tax credits claimed by PG&E Corporation's former subsidiary, National Energy & Gas Transmission, Inc.

[2] Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources – Dividends" within "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 6 of the Notes to the Consolidated Financial Statements.

[3] The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

[4] See Note 5 of the Notes to the Consolidated Financial Statements.

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a holding company that conducts its business through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility served approximately 5.2 million electricity distribution customers and approximately 4.4 million natural gas distribution customers at December 31, 2012.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and over the rates and terms and conditions of service governing the Utility on its interstate natural gas transportation contracts. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs (depreciation, tax, and financing expenses) of providing utility services. The primary CPUC proceedings are the general rate case ("GRC") and the gas transmission and storage ("GT&S") rate case which generally occur every few years and result in revenue requirements that are set for multi-year periods. The CPUC also periodically conducts a cost of capital proceeding, where it determines the capital structure the Utility must maintain (i.e., the relative weightings of common equity, long-term debt, and preferred equity) and authorizes the Utility to earn a specific rate of return on each capital component, including a rate of return on equity ("ROE"). The authorized revenue requirements the CPUC sets in the GRC and GT&S rate cases are set at levels to provide the Utility an opportunity to earn its authorized rates of return on its "rate base" – the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers. The primary FERC proceeding is the electric transmission owner ("TO") rate case which generally occurs on an annual basis. The FERC does not conduct a separate proceeding to authorize a specific rate of return on the Utility's FERC-jurisdictional assets. Instead, the rate of return is embedded in electric transmission revenues authorized by the FERC in TO rate cases. If the outcome of a TO rate case is reached through a FERC-approved settlement, the rate of return may not be specifically identified but rates would have been set to provide the Utility an opportunity to earn a reasonable rate of return. In other TO rate cases, the FERC may determine a specific rate of return after the FERC has held hearings and the parties have submitted briefs.

The Utility's ability to recover the revenue requirements that have been authorized by the CPUC in a GRC does not depend on the volume of the Utility's sales of electricity and natural gas services. This decoupling of revenues and sales eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand. However, fluctuations in operating and maintenance costs and the amount and timing of capital expenditures may impact the Utility's ability to earn its authorized rate of return. The Utility's ability to recover a portion of its revenue requirements that have been authorized by the CPUC in GT&S rate cases depends on the volume of natural gas transported. The Utility's ability to recover its revenue requirements that have been authorized by the FERC in a TO rate case depends on the volume of electricity sales.

The Utility also collects additional revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. Therefore, although the timing and amount of these costs can impact the Utility's revenue, these costs generally do not impact net income. The Utility's revenues and net income, however, also may be affected by incentive ratemaking mechanisms that adjust rates depending on the extent to which the Utility meets or fails to meet certain performance criteria, such as customer energy efficiency goals.

The Utility's revenue requirements are set based on forecasted costs. Differences in actual costs could negatively affect the Utility's ability to earn its authorized return. Differences can occur for numerous reasons, including unanticipated costs related to storms, outages, catastrophic events, or to comply with new legislation, regulations, or orders; or if the Utility is required to pay third-party claims that are not recoverable through insurance. The CPUC could also disallow recovery of costs that it finds were not prudently or reasonably incurred. Finally, there may be some types of costs that the CPUC has determined will not be recoverable through rates or for which the Utility does not seek recovery, such as certain costs associated with the Utility's natural gas system, penalties associated with investigations or violations, and environmental-related liabilities associated with the Utility's natural gas compressor station located in Hinkley, California, as described more fully below.

This is a combined annual report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

**Key Factors Affecting Results of Operations and Financial Condition**

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have continued to be materially affected by costs the Utility has incurred to improve the safety and reliability of its natural gas operations, as well as by costs related to the ongoing regulatory proceedings, investigations, and civil lawsuits that commenced following the rupture of one of the Utility's natural gas transmission pipelines in San Bruno, California on September 9, 2010 (the "San Bruno accident"). Through December 31, 2012, PG&E Corporation and the Utility have incurred cumulative charges of approximately $1.83 billion related to the San Bruno accident and natural gas matters. For 2012, this amount includes pipeline-related expenses of $477 million and capital expenditures of $353 million that will not be recoverable through rates. (See "CPUC Gas Safety Rulemaking Proceeding" below.) These matters and a number of other factors will continue to have a material negative impact on PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows.

- *The Outcome of Matters Related to the Utility's Natural Gas System.* The Utility forecasts that it will incur total pipeline-related costs ranging from $400 million to $500 million in 2013 that will not be recoverable through rates. These amounts include costs to perform work under the Utility's pipeline safety enhancement plan that were disallowed by the CPUC, as well as costs related to the Utility's multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way; costs associated with the integrity of transmission pipelines and other gas-related work; and legal and regulatory expenses. (See "Operating and Maintenance" below.) In addition, PG&E Corporation and the Utility believe that the CPUC will impose penalties on the Utility of at least $200 million in connection with three pending CPUC investigations and other potential enforcement matters. The ultimate amount of penalties could be materially higher and the Utility may also incur costs to implement any remedial actions the CPUC may order the Utility to perform. (See "Pending CPUC Investigations and Enforcement Matters" below.) An ongoing investigation of the San Bruno accident by federal, state, and local authorities may result in the imposition of civil or criminal penalties on the Utility. (See "Criminal Investigation" below.) Finally, PG&E Corporation and the Utility believe it is reasonably possible that they may incur additional charges of up to $145 million for estimated third-party claims related to the San Bruno accident. (See "Third-Party Claims" below.)

- *Authorized Rate of Return, Capital Structure, and Financing Needs* . The CPUC has authorized the Utility's capital structure through 2015 for the Utility's electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base , consisting of 52% common equity and 48% debt and preferred stock. The CPUC also authorized the Utility to earn a ROE of 10.40% beginning January 1, 2013, compared to the 11.35% previously authorized. (See "2013 Cost of Capital Proceeding" below.) In addition, the FERC has ordered the Utility to revise its requested revenue requirements and rates in its pending TO rate case to reflect a 9.1% ROE on electric transmission assets, rather than the 11.5% ROE originally requested by the Utility. (See "FERC Transmission Owner Rate Case" below.) PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure. The Utility has incurred significant expenses that are not recoverable through rates, which has increased the Utility's equity needs. In 2012, PG&E Corporation made equity contributions to the Utility of $885 million, which were funded primarily through common stock issuances that had a material dilutive effect on PG&E Corporation's earnings per common share. PG&E Corporation forecasts that it will issue additional common stock of approximately $1 billion in 2013 to fund the Utility's equity needs. Issuances that are used to fund the Utility's equity needs that are attributable to unrecoverable costs and penalties will have an additional dilutive effect. The Utility's debt and equity financing needs also will be affected by other factors, including the timing and amount of the Utility's capital expenditures, operating expenses, and collateral requirements associated with price risk management activities. The Utility forecasts that capital spending will total approximately $5.1 billion in 2013, including capital projects related to its pipeline safety enhancement plan. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by changes in their respective credit ratings, the outcome of natural gas matters, general economic and market conditions, and other factors. (See "Liquidity and Financial Resources" below.)

- *The Timing and Outcome of Ratemaking Proceedings* . The Utility's financial results are affected by the timing and outcome of ratemaking proceedings. The CPUC issued decisions in 2011 that determined the majority of the Utility's base revenue requirements through 2013. In November 2012, the Utility filed its 2014 GRC application with the CPUC to request that the CPUC determine the amount of revenue requirements the Utility is authorized to collect through rates for its electric generation operations and electric and natural gas distribution from 2014 through 2016. The Utility has requested that the CPUC increase the Utility's base revenues for 2014 by $1.28 billion over the comparable revenues for 2013 that were previously authorized. (See "2014 General Rate Case" below.) The FERC is expected to determine in the pending TO rate case the amount of electric transmission revenues the Utility can recover beginning in May 2013. (See "FERC Transmission Owner Rate Case" below.) In addition, in late 2013, the Utility expects to file an application with the CPUC to initiate the Utility's 2015 GT&S rate case in which the CPUC will determine the rates, and terms and conditions of the Utility's gas transmission and storage services beginning January 1, 2015. The outcome of these ratemaking proceedings can be affected by many factors, including general economic conditions, the level of customer rates, regulatory policies, and political considerations.

- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* Rates are primarily set based on forecasts and assumptions about the amount of operating costs and capital expenditures the Utility will incur in future periods. PG&E Corporation's and the Utility's net income is negatively affected when the revenues provided by rates are not sufficient for the Utility to recover the costs it actually incurs. In 2012, in addition to the non-recoverable costs related to the Utility's natural gas system described above, the Utility incurred costs of $255 million to improve the safety and reliability of its electric and natural gas operations that it will not recover in rates. The Utility forecasts that it will incur approximately $250 million to make additional incremental improvements in 2013 that it will not recover in rates. (See "Operating and Maintenance" below.) In addition, 2013 net income will be negatively affected by costs related to capital expenditures that the Utility forecasts will exceed authorized levels. Any future increase in the Utility's environmental-related liabilities that are not recoverable through rates, such as costs associated with its natural gas compressor station located in Hinkley, California, also will negatively affect PG&E Corporation's and the Utility's net income. For 2012, the Utility recorded total charges to net income of $127 million for environmental remediation related to the Hinkley site. (See "Environmental Matters" below.) Other differences between the amount or timing of the Utility's actual costs and forecasted or authorized amounts may also affect the Utility's ability to earn its authorized ROE.

**Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for 2012**

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and earnings per common share for the year ended December 31, 2012:

| (in millions, except per share amounts) | Earnings | Earnings Per Common Share (Diluted) |
|---|---|---|
| **Income Available for Common Shareholders - 2011** | $ 844 | $ 2.10 |
| Increase in rate base earnings | 80 | 0.19 |
| Natural gas matters [(1)] | 32 | 0.15 |
| Storm and outage expenses | 28 | 0.06 |
| Litigation and regulatory matters | 27 | 0.06 |
| Gas transmission revenues | 15 | 0.04 |
| Environmental-related costs | 11 | 0.03 |
| Planned incremental work | (151) | (0.36) |
| Employee operational performance incentive | (33) | (0.08) |
| Energy efficiency incentive | (3) | (0.01) |
| Increase in shares outstanding [(2)] | - | (0.19) |
| Other | (34) | (0.07) |
| **Income Available for Common Shareholders - 2012** | **$ 816** | **$ 1.92** |

[(1)] The Utility incurred charges related to natural gas matters of $812 million and $739 million, pre-tax, for 2012 and 2011, respectively. The amount shown above represents the favorable tax impact attributable to the lower amount of non-deductible penalties recorded in 2012 of $17 million, as compared to $200 million recorded in 2011.

[(2)] Represents the impact of a higher number of shares outstanding at December 31, 2012, compared to the number of shares outstanding at December 31, 2011. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including expenses related to natural gas matters. This has no dollar impact on earnings.

## CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This 2012 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report.

These forward-looking statements relate to, among other matters, estimated losses associated with various investigations; estimated losses and insurance recoveries associated with the civil litigation arising from the San Bruno accident; forecasts of costs the Utility will incur to make safety and reliability improvements, including costs to perform work under the pipeline safety enhancement plan, that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to environmental remediation, tax, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and terms of the resolution of pending investigations and enforcement matters related to the Utility's natural gas system operating practices and the San Bruno accident, including the ultimate amount of penalties the Utility will be required to pay, the cost of any remedial actions the Utility may be ordered to perform, and whether the resolution is reached through settlement negotiations, or a fully litigated proceeding; the ultimate amount of third-party claims associated with the San Bruno accident and the timing and amount of related insurance recoveries; the ultimate amount of punitive damages, if any, the Utility may incur related to third-party claims; and the ultimate amount of civil or criminal penalties, if any, the Utility may incur related to the criminal investigation;

- the outcomes of current ratemaking proceedings, such as the 2014 GRC and the pending TO rate case; the outcome of future ratemaking and regulatory proceedings, such as the 2015 GT&S rate case, and the CPUC's natural gas rulemaking proceeding in which the CPUC will consider the Utility's proposed scope, timing, and cost recovery mechanisms that will apply to the second phase of the pipeline safety enhancement plan; and the outcomes of other ratemaking and regulatory proceedings;

- the ultimate amount of costs the Utility incurs in the future that are not recovered through rates, including costs to perform work under the pipeline safety enhancement plan, to identify and remove encroachments from transmission pipeline easements, and to perform incremental work to improve the safety and reliability of electric and natural gas operations;

- the outcome of future investigations or proceedings that may be commenced by the CPUC or other regulatory authorities relating to the Utility's compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of its electric and gas facilities;

- whether PG&E Corporation and the Utility are able to repair the reputational harm that they have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident, the related civil litigation, and the pending investigations, including any charge or finding of criminal liability;

- the level of equity contributions that PG&E Corporation must make to the Utility to enable the Utility to maintain its authorized capital structure as the Utility incurs charges and costs, including costs associated with natural gas matters and penalties imposed in connection with the pending investigations, that are not recoverable through rates or insurance;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover compliance and remediation costs from third parties or through rates or insurance; and the ultimate amount of costs the Utility incurs in connection with environmental remediation liabilities that are not recoverable through rates or insurance, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the operations, seismic design, security, safety, or decommissioning of nuclear facilities, including the Utility's Diablo Canyon nuclear power plant ("Diablo Canyon"), or relating to the storage of spent nuclear fuel, cooling water intake, or other issues; and the ability of the Utility to relicense the Diablo Canyon units;

- the impact of weather-related conditions or events (such as storms, tornadoes, floods, drought, solar or electromagnetic events, and wildland and other fires), natural disasters (such as earthquakes, tsunamis, and pandemics), and other events (such as explosions, fires, accidents, mechanical breakdowns, equipment failures, human errors, and labor disruptions), as well as acts of terrorism, war, or vandalism, including cyber-attacks, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;

- the impact of environmental laws and regulations aimed at the reduction of carbon dioxide and other greenhouse gases ("GHG"s), and whether the Utility is able to recover associated compliance costs, including the cost of emission allowances and offsets, that the Utility may incur under cap-and-trade regulations;

- changes in customer demand for electricity ("load") and natural gas resulting from unanticipated population growth or decline in the Utility's service area, general and regional economic and financial market conditions, the extent of municipalization of the Utility's electric distribution facilities, changing levels of "direct access" customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators," and the development of alternative energy technologies including self-generation and distributed generation technologies;

- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its energy commodity costs through rates;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect customer, vendor, and financial data contained in such systems and networks; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation are not recoverable through insurance, rates, or from other third parties;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the outcome of proceedings and investigations relating to the Utility's natural gas operations affects the Utility's ability to make distributions to PG&E Corporation in the form of dividends or share repurchases; and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, or regulations; and

- the impact of changes in generally accepted accounting principles, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see "Risk Factors" below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

**RESULTS OF OPERATIONS**

The table below details certain items from the accompanying Consolidated Statements of Income for 2012, 2011, and 2010:

| | Year ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2012** | **2011** | **2010** |
| **Utility** | | | |
| Electric operating revenues | $ 12,014 | $ 11,601 | $ 10,644 |
| Natural gas operating revenues | 3,021 | 3,350 | 3,196 |
| **Total operating revenues** | **15,035** | **14,951** | **13,840** |
| Cost of electricity | 4,162 | 4,016 | 3,898 |
| Cost of natural gas | 861 | 1,317 | 1,291 |
| Operating and maintenance | 6,045 | 5,459 | 4,432 |
| Depreciation, amortization, and decommissioning | 2,272 | 2,215 | 1,905 |
| **Total operating expenses** | **13,340** | **13,007** | **11,526** |
| Operating income | 1,695 | 1,944 | 2,314 |
| Interest income | 6 | 5 | 9 |
| Interest expense | (680) | (677) | (650) |
| Other income, net | 88 | 53 | 22 |
| Income before income taxes | 1,109 | 1,325 | 1,695 |
| Income tax provision | 298 | 480 | 574 |
| Net income | 811 | 845 | 1,121 |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 797** | **$ 831** | **$ 1,107** |
| **PG&E Corporation, Eliminations, and Other** [1] | | | |
| Operating revenues | $ 5 | $ 5 | $ 1 |
| Operating expenses | 7 | 7 | 7 |
| Operating loss | (2) | (2) | (6) |
| Interest income | 1 | 2 | - |
| Interest expense | (23) | (23) | (34) |
| Other (expense) income, net | (18) | (4) | 5 |
| Loss before income taxes | (42) | (27) | (35) |
| Income tax benefit | (61) | (40) | (27) |
| **Net income (loss)** | **$ 19** | **$ 13** | **$ (8)** |
| **Consolidated Total** | | | |
| Operating revenues | $ 15,040 | $ 14,956 | $ 13,841 |
| Operating expenses | 13,347 | 13,014 | 11,533 |
| Operating income | 1,693 | 1,942 | 2,308 |
| Interest income | 7 | 7 | 9 |
| Interest expense | (703) | (700) | (684) |
| Other income, net | 70 | 49 | 27 |
| Income before income taxes | 1,067 | 1,298 | 1,660 |
| Income tax provision | 237 | 440 | 547 |
| Net income | 830 | 858 | 1,113 |
| Preferred stock dividend requirement of subsidiary | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 816** | **$ 844** | **$ 1,099** |

The following presents the Utility's operating results for 2012, 2011, and 2010.

***Electric Operating Revenues***

The Utility's electric operating revenues consist of amounts charged to customers for electricity generation, transmission and distribution services, as well as amounts charged to customers to recover the cost of electricity procurement and the cost of public purpose, energy efficiency, and demand response programs.

The following table provides a summary of the Utility's total electric operating revenues:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Revenues excluding passed-through costs | $ 6,280 | $ 6,150 | $ 5,473 |
| Revenues for recovery of passed-through costs | 5,734 | 5,451 | 5,171 |
| **Total electric operating revenues** | **$ 12,014** | **$ 11,601** | **$ 10,644** |

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $413 million, or 4%, in 2012 compared to 2011. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $283 million, primarily due to an increase in the cost of electricity (See "Cost of Electricity" below), the cost of public purpose programs, and pension contributions. Electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $130 million, primarily due to an increase in base revenues as authorized in the 2011 GRC and in the TO rate case.

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $957 million, or 9%, in 2011 compared to 2010. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $280 million, primarily due to increases in the cost of electricity (see "Cost of Electricity" below), the cost of public purpose programs, and pension contributions. Electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $677 million. The increase is primarily due to additional base revenues that were authorized by the CPUC in the 2011 GRC and for various separately funded projects, and authorized by the FERC in the TO rate case that became effective March 1, 2011.

The Utility's future electric operating revenues, excluding revenues intended to recover costs that are passed through to customers , are expected to increase in 2013 as authorized by the CPUC in the 2011 GRC. This increase to future revenues will be offset by the lower revenues authorized by the CPUC in the 2013 Cost of Capital proceeding. (See "Regulatory Matters" below.) Additionally, the Utility's future electric operating revenues are expected to be impacted by revenues authorized by the FERC in the TO rate case (these increased revenues are expected to become effective on May 1, 2013) and by the CPUC in the 2014 GRC, which was filed on November 14, 2012. Future electric operating revenues will also be impacted by the cost of electricity and other revenues intended to recover costs that are passed through to customers.

***Cost of Electricity***

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, and realized gains and losses on price risk management activities. (See Note 10 of the Notes to the Consolidated Financial Statements.) The Utility's cost of electricity is passed through to customers. The Utility's cost of electricity excludes non-fuel costs associated with operating the Utility's own generation facilities and electric transmission and distribution system, which are included in operating and maintenance expense in the Consolidated Statements of Income.

The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Cost of purchased power | $ 3,873 | $ 3,719 | $ 3,647 |
| Fuel used in own generation facilities | 289 | 297 | 251 |
| **Total cost of electricity** | **$ 4,162** | **$ 4,016** | **$ 3,898** |
| Average cost of purchased power per kWh [1] | $ 0.079 | $ 0.089 | $ 0.081 |
| Total purchased power (in millions of kWh) | **48,933** | **41,958** | **44,837** |

[1] Kilowatt-hour

The Utility's total cost of electricity increased by $146 million, or 4%, in 2012 compared to 2011, primarily due to an increase in the volume of power purchased as customer demand increased and higher costs to purchase renewable energy. The higher cost of electricity was partially offset by the decrease in the average cost of purchased power which reflected lower spot prices. The volume of power the Utility purchases is driven by customer demand, the availability of the Utility's own generation facilities, and the cost effectiveness of each source of electricity.

The Utility's total cost of electricity increased by $118 million, or 3%, in 2011 compared to 2010. The increase was due to an increase in the average cost of purchased power resulting from increased renewable energy deliveries and higher transmission costs.

Various factors will affect the Utility's future cost of electricity, including the market prices for electricity and natural gas, the availability of Utility-owned generation, and changes in customer demand. Additionally, the cost of electricity is expected to be impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with current and future California law and regulatory requirements. The Utility's future cost of electricity also will be affected by legislation and rules applicable to GHG emissions. (See "Environmental Matters" below.)

***Natural Gas Operating Revenues***

The Utility's natural gas operating revenues consist of amounts charged for transportation, distribution, and storage services, as well as amounts charged to customers to recover the cost of natural gas procurement and public purpose programs.

The following table provides a summary of the Utility's natural gas operating revenues:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Revenues excluding passed-through costs | $ 1,772 | $ 1,696 | $ 1,627 |
| Revenues for recovery of passed-through costs | 1,249 | 1,654 | 1,569 |
| **Total natural gas operating revenues** | **$ 3,021** | **$ 3,350** | **$ 3,196** |

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, decreased by $329 million, or 10%, in 2012 compared to 2011. Revenues intended to recover costs that are passed through to customers and do not impact net income decreased by $405 million primarily due to a decrease in the cost of natural gas. Natural gas operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $76 million, primarily due to an increase in base revenues as authorized in the 2011 GT&S rate case and the 2011 GRC and increases in natural gas storage revenues.

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $154 million, or 5%, in 2011 compared to 2010. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $85 million, primarily due to an increase in the costs of public purpose programs and pension contributions. Natural gas operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $69 million, primarily due to an increase in authorized base revenue, partially offset by a decrease in natural gas storage revenues. (The Utility's storage facilities were at capacity throughout 2011 and less gas was transported from storage due to the milder weather that prevailed in 2011 compared to 2010. As result, the Utility was unable to accept more gas for storage.)

The Utility's operating revenues for natural gas transmission services are expected to increase for 2013 and 2014 as authorized by the CPUC in the 2011 GT&S rate case and will also be impacted by revenues authorized by the CPUC in the 2014 GRC. The Utility's revenues for natural gas distribution services in 2013, excluding revenues intended to recover passed-through costs, will also reflect revenue increases authorized by the CPUC in the 2011 GRC. These increases to future revenues will be offset by the lower revenues authorized by the CPUC in the 2013 Cost of Capital proceeding. (See "Regulatory Matters" below.) Additionally, the Utility's future operating revenues will reflect those revenues authorized by the CPUC under the Utility's pipeline safety enhancement plan. (See "Natural Gas Matters" below.) The Utility's future gas operating revenues also will be impacted by the cost of natural gas, natural gas throughput volume, and other factors.

***Cost of Natural Gas***

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas and realized gains and losses on price risk management activities. (See Note 10 of the Notes to the Consolidated Financial Statements.) The Utility's cost of natural gas is passed through to customers. The Utility's cost of natural gas excludes the cost of operating the Utility's gas transmission and distribution system, which is included in operating and maintenance expense in the Consolidated Statements of Income.

The following table provides a summary of the Utility's cost of natural gas:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Cost of natural gas sold | $ 676 | $ 1,136 | $ 1,119 |
| Transportation cost of natural gas sold | 185 | 181 | 172 |
| **Total cost of natural gas** | **$ 861** | **$ 1,317** | **$ 1,291** |
| Average cost per Mcf of natural gas sold | $ 2.91 | $ 4.49 | $ 4.69 |
| Total natural gas sold (in millions of Mcf) (1) | 232 | 253 | 249 |

(1) One thousand cubic feet

The Utility's total cost of natural gas decreased by $456 million, or 35%, in 2012 compared to 2011, primarily due to a lower average market price of natural gas during 2012.

The Utility's total cost of natural gas increased by $26 million, or 2%, in 2011 compared to 2010, primarily due to the absence of a $49 million refund the Utility received in 2010 to be passed through to customers as part of a litigation settlement.

The Utility's future cost of natural gas will be affected by the market price of natural gas and changes in customer demand. In addition, the Utility's future cost of natural gas may be affected by federal or state legislation or rules to regulate the GHG emissions from the Utility's natural gas transportation and distribution facilities and from natural gas consumed by the Utility's customers.

***Operating and Maintenance***

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer billing and service expenses, the cost of public purpose programs, and administrative and general expenses. The Utility's ability to earn its authorized rate of return depends in part on its ability to manage its expenses and to achieve operational and cost efficiencies.

The Utility's operating and maintenance expenses (including costs passed through to customers) increased by $586 million, or 11%, from $5,459 million in 2011 to $6,045 million in 2012. Excluding costs passed through to customers, operating and maintenance expense increased $488 million, primarily due to costs incurred to improve the safety and reliability of electric and natural gas operations that were $255 million higher than amounts assumed under the 2011 rate cases. The remaining increase was attributable to $73 million of net costs associated with natural gas matters (see table below), $56 million of employee operational performance incentive, and $26 million of planned maintenance costs associated with the Gateway Generating Station. These costs were partially offset by a $25 million decrease in legal and regulatory matters, including penalties associated with the Rancho Cordova accident in 2011. Costs that are passed through to customers and do not impact net income increased by $98 million, primarily due to costs associated with advanced electric and gas meters that use SmartMeter ™ technology and pension contributions.

The Utility's operating and maintenance expenses (including costs passed through to customers) increased by $1,027 million, or 23%, from $4,432 million in 2010 to $5,459 million in 2011. Excluding costs passed through to customers, operating and maintenance expenses increased by $817 million in 2011 compared to 2010, primarily due to a $456 million increase in costs for natural gas matters. (See table below.) The remaining increase in operating and maintenance costs was attributable to a number of factors, including $122 million for estimated environmental remediation costs and other liabilities associated with Hinkley natural gas compressor site and approximately $82 million for labor and other maintenance-related costs, primarily associated with higher storm costs. Additionally, legal and regulatory matters increased $32 million, including penalties associated with the Rancho Cordova accident. Costs that are passed through to customers and do not impact net income increased by $210 million primarily due to pension expense, public purpose programs, and meter reading.

The following table provides a summary of the Utility's costs associated with natural gas matters, included in operating and maintenance expenses:

| (in millions) | 2012 | 2011 | 2010 | Total |
|---|---|---|---|---|
| Pipeline-related expenses | $ 477 | $ 483 | $ 63 | $ 1,023 |
| Disallowed capital expenditures | 353 | - | - | 353 |
| Accrued penalties | 17 | 200 | - | 217 |
| Third-party claims | 80 | 155 | 220 | 455 |
| Insurance recoveries | (185) | (99) | - | (284) |
| Contribution to City of San Bruno | 70 | - | - | 70 |
| **Total natural gas matters** | **$ 812** | **$ 739** | **$ 283** | **$ 1,834** |

The Utility incurred net costs of $812 million, $739 million, and $283 million during 2012, 2011 and 2010, respectively, in connection with natural gas matters that are not recoverable through rates. These amounts primarily include pipeline-related expenses which consist of costs to validate safe operating pressures, conduct strength testing, and perform other work (including work within the scope of the Utility's pipeline safety enhancement plan), as well as associated legal and regulatory costs. In addition, a $353 million charge was recorded in 2012 for disallowed capital expenditures related to the Utility's pipeline safety enhancement plan that are forecasted to exceed the CPUC's authorized levels or that were specifically disallowed. Also included above are estimated penalties related to the CPUC's pending investigations and other potential enforcement matters, accruals for third-party claims related to the San Bruno accident, and a contribution to the City of San Bruno. These costs were partially offset by insurance recoveries related to third-party claims. (See "Natural Gas Matters" below.)

The Utility forecasts that it will incur total pipeline-related costs ranging from $400 million to $500 million in 2013 that will not be recoverable through rates. These amounts include costs to perform work under the Utility's pipeline safety enhancement plan that were disallowed by the CPUC. These amounts also include emerging work related to the Utility's multi-year effort to identify and remove encroachments (such as building structures and vegetation overgrowth) from transmission pipeline rights-of-way, as well as costs associated with the integrity of transmission pipelines and other gas-related work. The Utility also expects it will continue to incur legal and regulatory expenses associated with its natural gas system. The Utility may incur costs to implement any remedial actions the CPUC may order the Utility to perform. (See "Natural Gas Matters – Pending CPUC Investigations and Enforcement Matters" below.)

Future operating and maintenance expense will also continue to be affected by other costs associated with natural gas matters that are not recoverable through rates, including any additional charges for third-party claims arising from the San Bruno accident that are not recoverable through insurance, additional charges for civil or criminal penalties, or punitive damages, if any, that may be imposed on the Utility. (See "Natural Gas Matters" below.)

The Utility forecasts that it will incur expenses in 2013 that are approximately $250 million higher than amounts assumed under the 2011 GRC and GT&S rate case as the Utility works to improve the safety and reliability of its electric and natural gas operations.

***Depreciation, Amortization, and Decommissioning***

The Utility's depreciation and amortization expense consists of depreciation and amortization on plant and regulatory assets, and decommissioning expenses associated with fossil fuel-fired generation facilities and nuclear power facilities. The Utility's depreciation, amortization, and decommissioning expenses increased by $57 million, or 3%, in 2012 compared to 2011, primarily due to capital additions.

The Utility's depreciation, amortization, and decommissioning expenses increased by $310 million, or 16%, in 2011 compared to 2010, primarily due to capital additions and an increase in depreciation rates as authorized by the 2011 GRC and 2011 GT&S rate cases.

The Utility's depreciation expense for future periods is expected to be affected as a result of changes in capital expenditures and the implementation of new depreciation rates as authorized by the CPUC in future GRCs and GT&S rate cases. Future TO rate cases authorized by the FERC will also have an impact on depreciation rates.

***Interest Income and Interest Expense***

There were no material changes to interest income and interest expense for 2012 compared to 2011 or for 2011 compared to 2010.

***Other Income, Net***

The Utility's other income, net increased by $35 million, in 2012 compared to 2011. The increase was primarily due to an increase in allowance for equity funds used during construction ("AFUDC") as the average balance of construction work in progress was higher in 2012 as compared to 2011.

The Utility's other income, net increased by $31 million, in 2011 compared to 2010 when the Utility incurred costs to support a California ballot initiative that appeared on the June 2010 ballot that were not recoverable in rates. The increase was partially offset by a decrease in AFUDC as the average balance of construction work in progress was lower in 2011 compared to 2010.

***Income Tax Provision***

The Utility's income tax provision decreased by $182 million, or 38%, in 2012 compared to 2011. The effective tax rates were 27% and 36% for 2012 and 2011, respectively. The effective tax rates for 2012 decreased compared to 2011, primarily due to lower non-tax deductible penalties related to natural gas matters, and higher state benefits received and deductions in 2012, including a benefit associated with a California research and development claim, with no comparable amount in 2011; a higher California tax deduction resulting from an accounting method change for repairs as compared to 2011; and a California tax benefit associated with shorter depreciable lives related to meters that use SmartMeter ™ technology recorded in 2012 with no comparable amount in 2011.

The Utility's income tax provision decreased by $94 million, or 16%, in 2011 compared to 2010. The effective tax rates were 36% and 34% for 2011 and 2010, respectively. The effective tax rate for 2011 increased as compared to 2010, mainly due to non- tax deductible penalties related to natural gas matters recorded in 2011, with no comparable penalties recorded in 2010, partially offset by a benefit associated with a loss carryback recorded in 2011 and the reversal of a deferred tax asset attributable to the Medicare Part D subsidy, which affected the tax provision balance in 2010, with no comparable effect in 2011.

The differences between the Utility's income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations for 2012, 2011, and 2010 were as follows:

| | **2012** | **2011** | **2010** |
|---|---|---|---|
| Federal statutory income tax rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) | (3.0) | 1.6 | 1.0 |
| Effect of regulatory treatment of fixed asset differences | (3.9) | (4.2) | (3.0) |
| Tax credits | (0.6) | (0.5) | (0.4) |
| Benefit of loss carryback | (0.4) | (2.1) | - |
| Non deductible penalties | 0.5 | 6.3 | 0.2 |
| Other, net | (0.8) | 0.1 | 1.1 |
| **Effective tax rate** | **26.8%** | **36.2%** | **33.9%** |

**PG&E Corporation, Eliminations, and Other**

***Operating Revenues and Expenses***

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation. PG&E Corporation's interest expense relates to PG&E Corporation's outstanding senior notes, and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating results in 2012 compared to 2011 and 2011 compared to 2010.

## LIQUIDITY AND FINANCIAL RESOURCES

**Overview**

The Utility's ability to fund operations and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal load, volatility in energy commodity costs, collateral requirements related to price risk management activities, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and long-term financings, among other factors. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The Utility has short-term borrowing authority of $4.0 billion, including $500 million that is restricted to certain contingencies.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets.

PG&E Corporation's and the Utility's credit ratings may affect their access to the credit and capital markets and their respective financing costs in those markets. Credit rating downgrades may increase the cost of short-term borrowing, including the Utility's commercial paper and the costs associated with their respective credit facilities, and long-term debt.

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. The following table summarizes PG&E Corporation's and the Utility's cash positions:

| | December 31, | |
|---|---|---|
| **(in millions)** | **2012** | **2011** |
| PG&E Corporation | $ 207 | $ 209 |
| Utility | 194 | 304 |
| **Total consolidated cash and cash equivalents** | **$ 401** | **$ 513** |

In addition to these cash and cash equivalents, PG&E Corporation and the Utility hold restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 13 of the Notes to the Consolidated Financial Statements.)

**Revolving Credit Facilities and Commercial Paper Program**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and the Utility's commercial paper program at December 31, 2012:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Borrowings | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|---|
| PG&E Corporation | May 2016 | $ 300[1] | $ - | $ 120 | $ - | $ 180 |
| Utility | May 2016 | 3,000[2] | 266 | - | 370[3] | 2,364[3] |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 266** | **$ 120** | **$ 370** | **$ 2,544** |

[1] Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

[2] Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

[3] The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2012, the average outstanding borrowings under PG&E Corporation's revolving credit facility were $21 million and the maximum outstanding balance during the year was $120 million. For 2012, the Utility's average outstanding commercial paper balance was $665 million and the maximum outstanding balance during the year was $1.4 billion. The Utility did not borrow under its credit facility in 2012.

The revolving credit facilities include usual and customary covenants for revolving credit facilities of this type, including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. At December 31, 2012, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

See Note 4 of the Notes to the Consolidated Financial Statements for additional information about the credit facilities and the Utility's commercial paper program.

**2012 Financings**

***Utility***

The following table summarizes long-term debt issuances in 2012:

| (in millions) | Issue Date | Amount |
|---|---|---|
| **Senior Notes** | | |
| 4.45%, due 2042 | April 16 | $ 400 |
| 2.45%, due 2022 | August 16 | 400 |
| 3.75%, due 2042 | August 16 | 350 |
| **Total debt issuances in 2012** | | **$ 1,150** |

The net proceeds from the issuance of Utility senior notes in 2012 were used to repay a portion of outstanding commercial paper, and for general corporate purposes.

The Utility also received cash contributions of $885 million from PG&E Corporation during 2012 to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC.

***PG&E Corporation***

In November 2011, PG&E Corporation entered into an Equity Distribution Agreement providing for the sale of PG&E Corporation common stock having an aggregate gross offering price of up to $400 million. Sales of the shares are made by means of ordinary brokers' transactions on the New York Stock Exchange, or in such other transactions as agreed upon by PG&E Corporation and the sales agents and in conformance with applicable securities laws. For 2012, PG&E Corporation sold 5,446,760 shares of its common stock under the Equity Distribution Agreement for cash proceeds of $234 million, net of fees and commissions paid of $2 million. The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. As of December 31, 2012, PG&E Corporation had the ability to issue an additional $64 million of its common stock under the November Equity Distribution Agreement.

In March 2012, PG&E Corporation sold 5,900,000 shares of its common stock in an underwritten public offering for cash proceeds of $254 million, net of fees and commissions. In addition, during 2012, PG&E Corporation issued 6,803,101 shares of common stock under its 401 (k) plan, its Dividend Reinvestment and Stock Purchase Plan, and its share-based compensation plans, generating $263 million of cash.

**Future Financing Needs**

The amount and timing of the Utility's future debt financings and equity needs will depend on various factors, including:

- the amount of cash internally generated through normal business operations;
- the timing and amount of forecasted capital expenditures;
- the timing and amount of payments made to third parties in connection with the San Bruno accident, and the timing and amount of related insurance recoveries (see "Natural Gas Matters" below);
- the timing and amount of penalties imposed on the Utility in connection with the pending investigations and other potential enforcement matters related to the San Bruno accident and the Utility's natural gas operations (see "Natural Gas Matters" below);
- the timing and amount of pipeline-related expenses and other expenses to improve the safety and reliability of the Utility's electric and natural gas operations that are not recoverable through rates (see "Operating and Maintenance" above);
- the timing of the resolution of the Chapter 11 disputed claims and the amount of interest on these claims that the Utility will be required to pay (see Note 13 of the Notes to the Consolidated Financial Statements);
- the amount of future tax payments; and
- the conditions in the capital markets, and other factors.

PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In December 2012, the CPUC issued a final decision authorizing the Utility to maintain a capital structure consisting of 52% equity, 47% long-term debt and 1% preferred stock, beginning on January 1, 2013. The decision also reduced the authorized ROE from 11.35% to 10.40%. (See the "2013 Cost of Capital Proceeding" discussion in "Regulatory Matters" below.) The Utility's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters. Further, given the Utility's significant ongoing capital expenditures, it will continue to need equity contributions from PG&E Corporation to maintain its authorized capital structure.

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation also may use draws under its revolving credit facility to occasionally fund equity contributions on an interim basis. Additional common stock issued by PG&E Corporation in the future to fund further equity contributions to the Utility could have a material dilutive effect on PG&E Corporation's earnings per common share.

**Dividends**

The Board of Directors of PG&E Corporation and the Utility have each adopted a common stock dividend policy that is designed to meet the following three objectives:

- *Comparability:* Pay a dividend competitive with the securities of comparable companies based on payout ratio (the proportion of earnings paid out as dividends) and, with respect to PG&E Corporation, yield (i.e., dividend divided by share price);

- *Flexibility:* Allow sufficient cash to pay a dividend and to fund investments while avoiding having to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and

- *Sustainability:* Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

Each Board of Directors retains authority to change the common stock dividend rate at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors. In addition, before declaring a dividend, the CPUC requires that the PG&E Corporation Board of Directors give first priority to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The Boards of Directors must also consider the CPUC requirement that the Utility maintain, on average, its CPUC-authorized capital structure including a 52% equity component.

The Board of Directors of PG&E Corporation declared dividends of $0.455 per share for each of the quarters of 2012, for an annual dividend of $1.82 per share.

The following table summarizes PG&E Corporation's and the Utility's dividends paid:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| **PG&E Corporation:** | | | |
| Common stock dividends paid | $ 746 | $ 704 | $ 662 |
| Common stock dividends reinvested in Dividend Reinvestment and Stock Purchase Plan | 22 | 24 | 18 |
| **Utility:** | | | |
| Common stock dividends paid | $ 716 | $ 716 | $ 716 |
| Preferred stock dividends paid | 14 | 14 | 14 |

In December 2012, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $196 million, of which $191 million was paid on January 15, 2013 to shareholders of record on December 31, 2012. The remaining $5 million was reinvested under the Dividend Reinvestment and Stock Purchase Plan.

In December 2012, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on February 15, 2013, to shareholders of record on January 31, 2013.

As the Utility focuses on improving the safety and reliability of its natural gas and electric operations, and subject to the outcome of the matters described under "Natural Gas Matters" below, PG&E Corporation expects that its Board will continue to maintain the current quarterly common stock dividend.

**Utility**

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for 2012, 2011, and 2010 were as follows:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Net income | $ 811 | $ 845 | $ 1,121 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,272 | 2,215 | 1,905 |
| Allowance for equity funds used during construction | (107) | (87) | (110) |
| Deferred income taxes and tax credits, net | 684 | 582 | 762 |
| Disallowed capital expenditures | 353 | - | 36 |
| Other | 236 | 289 | 221 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (40) | (227) | (105) |
| Inventories | (24) | (63) | (43) |
| Accounts payable | (26) | 51 | 109 |
| Income taxes receivable/payable | (50) | (192) | (58) |
| Other current assets and liabilities | 272 | 36 | 123 |
| Regulatory assets, liabilities, and balancing accounts, net | 291 | (100) | (394) |
| Other noncurrent assets and liabilities | 256 | 414 | (331) |
| **Net cash provided by operating activities** | **$ 4,928** | **$ 3,763** | **$ 3,236** |

During 2012, net cash provided by operating activities increased by $1,165 million compared to 2011. This increase was primarily due to a decrease of $352 million in net collateral paid by the Utility related to price risk management activities, a $353 million disallowance for capital expenditures incurred in connection with its pipeline safety enhancement plan, a receipt of $250 million, net of legal fees, from the U.S. Treasury related to spent nuclear fuel costs, and a decrease in tax payments of $224 million. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

During 2011, net cash provided by operating activities increased $527 million compared to 2010 primarily due to a decrease of $214 million in net collateral paid by the Utility related to price risk management activities. This increase also reflects a decrease in tax payments of $121 million in 2011 compared to 2010. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as collateral and the timing and amount of customer billings and collections.

Future cash flow from operating activities will be affected by the timing and amount of payments to be made to third parties in connection with the San Bruno accident, including related insurance recoveries; the timing and amount of penalties that may be assessed, as well as any remedial actions the CPUC may order the Utility to perform; and the anticipated higher operating and maintenance costs associated with the Utility's natural gas and electric operations, among other factors. (See "Operating and Maintenance" above and "Natural Gas Matters" below.)

***Investing Activities***

The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. The amount and timing of the Utility's capital expenditures is affected by many factors such as the occurrence of storms and other events causing outages or damages to the Utility's infrastructure. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's cash flows from investing activities for 2012, 2011, and 2010 were as follows:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Capital expenditures | $ (4,624) | $ (4,038) | $ (3,802) |
| Decrease in restricted cash | 50 | 200 | 66 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,133 | 1,928 | 1,405 |
| Purchases of nuclear decommissioning trust investments | (1,189) | (1,963) | (1,456) |
| Other | 16 | 14 | 19 |
| **Net cash used in investing activities** | **$ (4,614)** | **$ (3,859)** | **$ (3,768)** |

Net cash used in investing activities increased by $755 million in 2012 compared to 2011. This increase was primarily due to an increase of $586 million in capital expenditures and a reduction in restricted cash released for resolved Chapter 11 disputed claims of $150 million.

Net cash used in investing activities increased by $91 million in 2011 compared to 2010, primarily due to an increase in capital expenditures of $236 million as compared to 2010. This increase was partially offset by a decrease of $134 million in restricted cash that was primarily due to releases from escrow for resolved Chapter 11 disputed claims in 2011, with few similar releases in 2010.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. (See "Capital Expenditures" below for further discussion of expected spending and significant capital projects.)

***Financing Activities***

The Utility's cash flows from financing activities for 2012, 2011, and 2010 were as follows:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Borrowings under revolving credit facilities | $ - | $ 208 | $ 400 |
| Repayments under revolving credit facilities | - | (208) | (400) |
| Net issuances (repayments) of commercial paper, net of discount of $3 in 2012, $4 in 2011, and $3 in 2010 | (1,021) | 782 | 267 |
| Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2011 and 2010 | - | 250 | 249 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2012, $8 in 2011, and $23 in 2010 | 1,137 | 792 | 1,327 |
| Short-term debt matured | (250) | (250) | (500) |
| Long-term debt matured or repurchased | (50) | (700) | (95) |
| Energy recovery bonds matured | (423) | (404) | (386) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution | 885 | 555 | 190 |
| Other | 28 | 54 | (73) |
| **Net cash provided by (used in) financing activities** | **$ (424)** | **$ 349** | **$ 249** |

In 2012, net cash provided by financing activities decreased by $773 million compared to the same period in 2011. In 2011, net cash provided by financing activities increased by $100 million compared to 2010. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

**PG&E Corporation**

As of December 31, 2012, PG&E Corporation's affiliates had entered into four tax equity agreements with two privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation has agreed to provide lease payments and investment contributions of up to $396 million to these companies in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. PG&E Corporation's financial exposure from these arrangements is generally limited to its lease payments and investment contributions to these companies. As of December 31, 2012, PG&E Corporation had made total payments of $361 million under these tax equity agreements and received $228 million in benefits and customer payments. Lease payments, investment contributions, benefits, and customer payments received are included in cash flows from operating and investing activities within the Consolidated Statements of Cash Flows.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the years ended December 31, 2012, 2011, and 2010: dividend payments, common stock issuances, borrowings and repayments under the revolving credit facility in 2012 and 2011, and transactions between PG&E Corporation and the Utility.

**CONTRACTUAL COMMITMENTS**

| | Payment due by period | | | | | |
|---|---|---|---|---|---|---|
| (in millions) | Less Than 1 Year | 1–3 Years | 3–5 Years | More Than 5 Years | | Total |
| **Contractual Commitments:** | | | | | | |
| **Utility** | | | | | | |
| Long-term debt [1] : | | | | | | |
| Fixed rate obligations | $ 1,035 | $ 2,148 | $ 1,824 | $ 17,305 | | $ 22,312 |
| Variable rate obligations | 2 | 8 | 941 | 153 | | 1,104 |
| Purchase obligations [2] : | | | | | | |
| Power purchase agreements : | | | | | | |
| Qualifying facilities ("QF") | 892 | 1,641 | 1,108 | 2,238 | | 5,879 |
| Renewable contracts (other than QF) | 1,356 | 3,881 | 4,107 | 30,958 | | 40,302 |
| Other power purchase agreements | 846 | 1,326 | 1,223 | 3,322 | | 6,717 |
| Natural gas supply, transportation and storage | 707 | 400 | 260 | 865 | | 2,232 |
| Nuclear fuel agreements | 113 | 322 | 295 | 878 | | 1,608 |
| Pension and other benefits [3] | 455 | 796 | 796 | 398 | [6] | 2,445 |
| Capital lease obligations [4] | 35 | 51 | 40 | 20 | | 146 |
| Operating leases [4] | 42 | 69 | 55 | 206 | | 372 |
| Preferred dividends [5] | 14 | 28 | 28 | - | | 70 |
| **PG&E Corporation** | | | | | | |
| Long-term debt [1] : | | | | | | |
| Fixed rate obligations | 20 | 355 | - | - | | 375 |

[1] Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2012 and outstanding principal for each instrument with the terms ending at each instrument's maturity. Variable rate obligations consist of pollution control bonds, due in 2016 and 2026 and related loans and are backed by letters of credit that expire on May 31, 2016. (See Note 4 of the Notes to the Consolidated Financial Statements.)

[2] This table includes power purchase agreements that have been approved by the CPUC and have completed major milestones for construction. (See Note 15 of the Notes to the Consolidated Financial Statements.)

[3] PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. (See Note 12 of the Notes to the Consolidated Financial Statements.)

[4] See Note 15 of the Notes to the Consolidated Financial Statements.

[5] Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

[6] Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount reflected represents only 1 year of contributions for the Utility's pension and other benefit plans.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2012, the Utility was committed to spending approximately $277 million for these conversions. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties, and communication utilities involved. The Utility expects to spend $86 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed, resulting in the capital expenditures being recoverable from customers.

The contractual commitments table above also excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 9 of the Notes to the Consolidated Financial Statements.

## CAPITAL EXPENDITURES

The Utility makes various capital investments in its electric generation and electric and natural gas transmission and distribution infrastructure to maintain and improve system reliability, safety, and customer service; to extend the life of or replace existing infrastructure; and to add new infrastructure to meet growth. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases. (See "2014 General Rate Case" below.) The Utility also collects additional revenue requirements to recover capital expenditures related to projects that have been specifically authorized by the CPUC, such as new power plants, gas or electric distribution projects, and the SmartMeter ™ advanced metering infrastructure.

The Utility's capital expenditures for property, plant, and equipment totaled $4.8 billion in 2012, $4.2 billion in 2011, and $3.9 billion in 2010. The Utility forecasts that capital expenditures will total approximately $5.1 billion in 2013, including expenditures related to its pipeline safety enhancement plan.

### *Natural Gas Pipeline Safety Enhancement Plan*

On December 28, 2012, the CPUC issued a decision that approved the Utility's proposed pipeline safety enhancement plan (filed in August 2011) but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs the Utility forecasted it would incur over the first phase of the plan (2011 through 2014). The CPUC decision limited the Utility's recovery of capital expenditures to $1.0 billion of the total $1.4 billion requested. As a result, the Utility recorded a charge of $353 million in 2012 for disallowed capital expenditures. (See "Natural Gas Matters – CPUC Gas Safety Rulemaking Proceeding" below.)

### *Oakley Generation Facility*

On December 20, 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California. The CPUC authorized the Utility to recover the purchase price through rates. During January 2013, several parties filed applications for rehearing of the CPUC decision. PG&E Corporation and Utility are uncertain whether the CPUC will modify its decision based on these applications.

## NATURAL GAS MATTERS

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows, have continued to be negatively affected by costs the Utility has incurred to improve the safety and reliability of the Utility's natural gas operations, as well as by costs related to the on-going regulatory proceedings, investigations, and civil lawsuits related to the San Bruno accident and the Utility's natural gas operations. Since the San Bruno accident, PG&E Corporation and the Utility have incurred total cumulative charges to net income of $1.83 billion related to natural gas matters.

| **(in millions)** | **2012** | **2011** | **2010** | **Total** |
|---|---|---|---|---|
| Pipeline-related expenses [1] | $ 477 | $ 483 | $ 63 | $ 1,023 |
| Disallowed capital expenditures [1] | 353 | - | - | 353 |
| Accrued penalties [2] | 17 | 200 | - | 217 |
| Third-party claims [3] | 80 | 155 | 220 | 455 |
| Insurance recoveries [3] | (185) | (99) | - | (284) |
| Contribution to City of San Bruno (4) | 70 | - | - | 70 |
| **Total natural gas matters** | **$ 812** | **$ 739** | **$ 283** | **$ 1,834** |

[1] See "CPUC Gas Safety Rulemaking Proceeding" below.

[2] See "Pending CPUC Investigations and Enforcement Matters" below.

[3] See "Third-Party Claims" below.

[4] On March 12, 2012, the Utility and the City of San Bruno entered into an agreement under which the Utility contributed $70 million to support the city and the community's recovery efforts.

**Pending CPUC Investigations and Enforcement Matters**

The CPUC is conducting three investigations of the Utility's natural gas operations that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident. (See Note 15 of the Notes to the Consolidated Financial Statements.) Although the Utility, the CPUC's Safety and Enforcement Division ("SED"), and other parties have engaged in settlement discussions in an effort to reach a stipulated outcome to resolve the investigations, the parties have not reached an agreement. PG&E Corporation and the Utility are uncertain whether or when any stipulated outcome might be reached. Any agreement regarding a stipulated outcome would be subject to CPUC approval.

The CPUC has concluded evidentiary hearings in each of these investigations. The CPUC administrative law judges ("ALJs") who oversee the investigations have adopted a revised procedural schedule, including the dates by which the parties' briefs must be submitted. The ALJs have also permitted the other parties (the City of San Bruno, The Utility Reform Network, and the City and County of San Francisco) to separately address in their opening briefs their allegations against the Utility, if any, in addition to the allegations made by the SED. The ALJs have ordered the SED and other parties to file single coordinated briefs to address potential monetary penalties and remedies (which could include remedial operational or policy measures) for all three investigations by April 26, 2013. After briefing has been completed, the ALJs will issue one or more presiding officer's decisions listing the violations determined to have been committed, the amount of penalties, and any required remedial actions. Based on the revised procedural schedule, one or more presiding officer's decisions will be issued by July 23, 2013. The decisions would become the final decisions of the CPUC thirty days after issuance unless the Utility or another party filed an appeal, or a CPUC commissioner requested review of the decision, within such time. (See "Penalties Conclusion" below.)

*Other Potential Enforcement Matters*

California gas corporations are required to provide notice to the CPUC of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The CPUC has authorized the SED to issue citations and impose penalties based on self-reported violations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the SED based on the Utility's self-report that it failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has paid the penalty and completed all of the missed leak surveys.) As of December 31, 2012, the Utility has submitted 34 self-reports with the CPUC, plus additional follow-up reports. The SED has not yet taken formal action with respect to the Utility's other self-reports. The SED may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file. (See "Penalties Conclusion" below.)

In addition, in July 2012, the Utility reported to the CPUC that it had discovered that its access to some pipelines has been limited by vegetation overgrowth or building structures that encroach upon some of the Utility's gas transmission pipeline rights-of-way. The Utility is undertaking a system-wide effort to identify and remove encroachments from its pipeline rights-of-way over a multi-year period. (See "Operating and Maintenance" above.) PG&E Corporation and the Utility are uncertain how this matter will affect the above investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced that could result in regulatory orders or the imposition of penalties on the Utility.

*Penalties Conclusion*

The CPUC can impose penalties of up to $20,000 per day, per violation. (For violations that are considered to have occurred on or after January 1, 2012, the statutory penalty has increased to a maximum of $50,000 per day, per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this wide discretion in determining penalties. The CPUC's delegation of enforcement authority to the SED allows the SED to use these factors in exercising discretion to determine the number of violations, but the SED is required to impose the maximum statutory penalty for each separate violation that the SED finds.

The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. In determining the amount of penalties the ALJs may consider the testimony of financial consultants engaged by the SED and the Utility. The SED's financial consultant prepared a report concluding that PG&E Corporation could raise approximately $2.25 billion through equity issuances, in addition to equity PG&E Corporation had already forecasted it would issue in 2012, to fund CPUC-imposed penalties on the Utility. The Utility's financial consultant disagreed with this financial analysis and asserted that a fine in excess of financial analysts' expectations, which the consultant's report cited as a mean of $477 million, would make financing more difficult and expensive. The ALJs have scheduled a hearing to be held on March 4 and March 5, 2013 to consider the SED's and Utility's testimony. The SED and other parties are scheduled to file briefs to address potential monetary penalties and remedies in all three investigations by April 26, 2013.

PG&E Corporation and the Utility believe it is probable that the Utility will incur penalties of at least $200 million in connection with these pending investigations and potential enforcement matters and have accrued this amount in their consolidated financial statements. PG&E Corporation and the Utility are unable to make a better estimate of probable losses or estimate the range of reasonably possible losses in excess of the amount accrued due to the many variables that could affect the final outcome of these matters and the ultimate amount of penalties imposed on the Utility could be materially higher than the amount accrued. These variables include how the CPUC and the SED will exercise their discretion in calculating the amount of penalties, including how the total number of violations will be counted; how the duration of the violations will be determined; whether the amount of penalties in each investigation will be determined separately or in the aggregate; how the financial resources testimony submitted by the SED and the Utility will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and whether and how the financial impact of non-recoverable costs the Utility has already incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered. (See "CPUC Gas Safety Rulemaking Proceeding" below.)

These estimates, and the assumptions on which they are based, are subject to change based on many factors, including rulings, orders, or decisions that may be issued by the ALJs; whether the outcome of the investigations is resolved through a fully litigated process or a stipulated outcome that is approved by the CPUC; whether the SED will take additional action with respect to the Utility's self-reports; and whether the CPUC or the SED takes any action with respect to the encroachment matter described above. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

**CPUC Gas Safety Rulemaking Proceeding**

The CPUC is conducting a rulemaking proceeding to develop and adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. On December 28, 2012, the CPUC issued a decision that approved most of the Utility's proposed pipeline safety enhancement plan to modernize and upgrade its natural gas transmission system, but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs the Utility forecasted it would incur over the first phase of the plan (2011 through 2014).

In its application filed in August 2011, the Utility forecasted that it would incur total plan-related costs of approximately $2.2 billion, composed of $1.4 billion in capital expenditures and $750 million in expenses. The CPUC decision prohibited the Utility from recovering any expenses incurred before December 20, 2012, the effective date of the decision, and from recovering certain categories of expenses that the Utility forecasts it will incur in 2013 and 2014. The CPUC decision also limits the Utility's recovery of capital expenditures to $1 billion. The Utility will be unable to recover any costs in excess of the adopted capital and expense amounts and the adopted amounts will be reduced by the cost of any plan project not completed and not replaced with a higher priority project. The CPUC also determined that the Utility should not recover in rates the costs of pressure testing pipeline placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC may disallow additional costs based on the final results of the Utility's pipeline records search and pipeline pressure validation work, which the Utility expects to complete by May 2013. The Utility is required to update its plan and file an application within 30 days after this work is completed.

The following table compares the Utility's requested expense and capital amounts (based on forecasts included in the August 2011 application) with the amounts authorized by the CPUC:

| (in millions) | 2011 | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|---|
| **Expense** | | | | | |
| Requested | $ 221[1] | $ 231 | $ 155 | $ 144 | $ 751 |
| Authorized | - | 3 | 73 | 89 | 165 |
| Difference | $ 221[1] | $ 228 | $ 82 | $ 55 | $ 586 |
| **Capital** | | | | | |
| Requested | $ 69 | $ 384 | $ 480 | $ 500 | $ 1,433 |
| Authorized | 47 | 260 | 348 | 348 | 1,003 |
| Difference | $ 22 | $ 124 | $ 132 | $ 152 | $ 430 |

(1) The Utility's August 2011 application did not request recovery of forecast 2011 plan-related expenses of $221 million.

For the year ended December 31, 2012, the Utility incurred total pipeline-related expenses of $477 million, including plan-related expenses of $271 million. As a result of the decision, the Utility also recorded a charge of $353 million for capital expenditures that are forecast to exceed the CPUC's authorized levels or that were specifically disallowed. All plan-related costs for 2013 and 2014 will be charged to net income in the period incurred. Unrecoverable plan-related costs are expected to range from approximately $150 million to $200 million in 2013 and a comparable amount in 2014. The CPUC stated that the Utility's recovery of the amounts authorized in the decision will be subject to refund, noting the possibility that further ratemaking adjustments may be made in the pending CPUC investigations in which the CPUC will address potential penalties to be imposed on the Utility. (See "Pending CPUC Investigations and Enforcement Matters" above.)

The CPUC delegated authority to the SED to oversee all of the Utility's work performed pursuant to the pipeline safety enhancement plan, including the authority to participate in all plan-related activities and review and modify all changes proposed by the Utility. The Utility must submit quarterly compliance reports to the CPUC that will include information about actual cost compared to authorized cost for each work project; the construction status of projects; and changes in scope and prioritization of projects. As a result of the compliance reporting process, the Utility could incur additional non-recoverable costs. The CPUC also ordered the SED to engage consultants to conduct management and financial audits to address safety-related corporate culture and historical spending. (As discussed below, the financial audit of the Utility's natural gas distribution spending will be considered in the 2014 GRC, but the scope and timing of the management audit is still uncertain.) (See "2014 GRC" below.)

On January 28, 2013, several parties filed applications for rehearing of the CPUC's decision. The applications for rehearing state, among other arguments, that the CPUC should have disallowed more of the Utility's costs and that the CPUC should have approved a reduced ROE for capital expenditures made under the plan. Several parties also have filed petitions for modification of the decision. It is uncertain whether or when the CPUC will grant these requests.

The second phase of the Utility's pipeline safety enhancement plan in 2015 will focus on pipeline segments in less populated areas, as well as certain pressure testing and pipeline replacement work that the CPUC deferred from the first phase. The Utility expects to address the scope, timing, and cost recovery of the second phase in late 2013 and request that changes to rates be made effective January 1, 2015.

**Criminal Investigation**

The U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office are conducting an investigation of the San Bruno accident and have indicated that the Utility is a target of the investigation. The Utility is cooperating with the investigation. PG&E Corporation and the Utility are uncertain whether any criminal charges will be brought against either company or any of their current or former employees.

PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Utility as a consequence of this investigation.

**Third-Party Claims**

In addition to the investigations and proceedings discussed above, at December 31, 2012, approximately 140 lawsuits involving third-party claims for personal injury and property damage, including two class action lawsuits, had been filed against PG&E Corporation and the Utility in connection with the San Bruno accident on behalf of approximately 450 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases were coordinated and assigned to one judge in the San Mateo County Superior Court. Many of the plaintiffs' claims have been resolved through settlements. The trial of the first group of remaining cases began on January 2, 2013 with pretrial motions and hearings. On January 14, 2013, the court vacated the trial and all pending hearings due to the significant number of cases that have been settled outside of court. The court has urged the parties to settle the remaining cases. As of February 8, 2013, the Utility has entered into settlement agreements to resolve the claims of approximately 140 plaintiffs. It is uncertain whether or when the Utility will be able to resolve the remaining claims through settlement.

At December 31, 2012, the Utility had recorded cumulative charges of $455 million for estimated third-party claims related to the San Bruno accident, including an $80 million charge made during 2012, primarily to reflect settlements and information exchanged by the parties during the settlement and discovery process. The Utility estimates it is reasonably possible that it may incur as much as an additional $145 million for third-party claims, for a total possible loss of $600 million. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with punitive damages, if any, related to these matters. The Utility has publicly stated that it is liable for the San Bruno accident and will take financial responsibility to compensate all of the victims for the injuries they suffered as a result of the accident. (See Note 15 to the Consolidated Financial Statements.)

The Utility has recognized cumulative insurance recoveries of $284 million for third-party claims, which included $185 million for 2012 and $99 million for 2011. Although the Utility believes that a significant portion of costs incurred for third-party claims relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries. (See Note 15 to the Consolidated Financial Statements.)

**Class Action Complaint**

On August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. To state their claims, the plaintiffs cited the SED's January 2012 investigative report of the San Bruno accident that alleged, from 1996 to 2010, the Utility spent less on capital expenditures and operations and maintenance expense for its natural gas transmission operations than it recovered in rates, by $95 million and $39 million, respectively. The SED recommended that the Utility should use such amounts to fund future gas transmission expenditures and operations. Plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of Section 17200 of the California Business and Professions Code ("Section 17200") and claim that this violation also constitutes a violation of California Public Utilities Code Section 2106 ("Section 2106"), which provides a private right of action for violations of the California constitution or state laws by public utilities. Plaintiffs seek restitution and disgorgement under Section 17200 and compensatory and punitive damages under Section 2106.

PG&E Corporation and the Utility contest the plaintiffs' allegations. In January 2013, PG&E Corporation and the Utility requested that the court dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. In the alternative, PG&E Corporation and the Utility requested that the court stay the proceeding until the CPUC investigations described above are concluded. The court has set a hearing on the motion for April 26, 2013. Due to the early stage of this proceeding, PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses that may be incurred in connection with this matter.

**Other Pending Lawsuits and Claim**

In October 2010, a purported shareholder derivative lawsuit was filed in San Mateo Superior Court following the San Bruno accident to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims, relating to the Utility's natural gas business. The judge has ordered that proceedings in the derivative lawsuit be delayed until further order of the court. On February 7, 2013, another purported shareholder derivative lawsuit was filed in U.S. District Court for the Northern District of California to seek recovery on behalf of PG&E Corporation for alleged breaches of fiduciary duty by officers and directors, among other claims.

In February 2011, the Board of Directors of PG&E Corporation authorized PG&E Corporation to reject a demand made by another shareholder that the Board of Directors (1) institute an independent investigation of the San Bruno accident and related alleged safety issues; (2) seek recovery of all costs associated with such issues through legal proceedings against those determined to be responsible, including Board of Directors members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board of Directors also reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board of Directors deems such investigation or litigation appropriate.

## REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's results of operations and financial condition.

### 2013 Cost of Capital Proceeding

On December 20, 2012, the CPUC issued a final decision authorizing the Utility to maintain a capital structure consisting of 52% equity, 47% long-term debt, and 1% preferred stock, beginning on January 1, 2013. This capital structure applies to the Utility's electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. In addition, the CPUC authorized the Utility to earn a rate of return on each component of the capital structure, including a ROE of 10.40%, compared to the 11% ROE requested by the Utility. The following table compares the 2012 and 2013 authorized capital structure and rates of return:

| | 2012 Authorized | | | 2013 Authorized | | |
|---|---|---|---|---|---|---|
| | Cost | Capital Structure | Weighted Cost | Cost | Capital Structure | Weighted Cost |
| Long-term debt | 6.05% | 46% | 2.78% | 5.52% | 47% | 2.59% |
| Preferred stock | 5.68% | 2% | 0.11% | 5.60% | 1% | 0.06% |
| Return on common equity | 11.35% | 52% | 5.90% | 10.40% | 52% | 5.41% |
| Overall Rate of Return | | | 8.79% | | | 8.06% |

The Utility estimates that the 2013 revenue requirement associated with the authorized cost of capital will be approximately $235 million less than the currently authorized revenue requirement. Approximately $165 million of this estimated decrease is attributable to the lower authorized ROE. Changes to the Utility's revenue requirement became effective on January 1, 2013.

The Utility and other parties have submitted a joint stipulation to the CPUC in which the parties agreed to continue the annual cost of capital adjustment mechanism that had been in effect since 2008, and to file the next full cost of capital applications in April 2015 for the 2016 test year. Under the mechanism as proposed to be continued, the Utility's ROE would be adjusted if the 12-month October-through-September average of the Moody's Investors Service long-term Baa utility bond index increases or decreases by more than 1.00% as compared to the applicable benchmark. If the adjustment mechanism is triggered, the Utility's authorized ROE, beginning January 1st of the following year, would be adjusted by one-half of the difference between the index and the benchmark. Additionally, the Utility's authorized costs of long-term debt and preferred stock would be updated to reflect actual August month-end embedded costs and forecasted interest rates for variable long-term debt, as well as new long-term debt and preferred stock scheduled to be issued. In any year where the 12-month average yield triggers an automatic ROE adjustment, that average would become the new benchmark.

The CPUC is scheduled to issue a proposed decision by March 15, 2013 with a final decision by April 18, 2013.

### 2014 General Rate Case

On November 15, 2012, the Utility filed its 2014 GRC application with the CPUC. In the Utility's 2014 GRC, the CPUC will determine the annual amount of revenue requirements that the Utility will be authorized to collect from customers from 2014 through 2016 to recover its anticipated costs for electric and natural gas distribution and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return.

The Utility has requested that the CPUC increase the Utility's authorized base revenues for 2014 by a total of $1.28 billion over the comparable base revenues for 2013 that were previously authorized by the CPUC. Over the 2014-2016 GRC period, the Utility plans to make annual additional capital investments of nearly $4 billion in electric and natural gas distribution and electric generation infrastructure. The Utility forecasts that its 2014 weighted average rate base for the portion of the Utility's business reviewed in the GRC will be $21.4 billion.

The following tables compare the requested 2014 revenue requirement amounts by line of business with the comparable revenue requirements currently authorized for 2013:

| **(in millions)**<br>**Line of Business:** | **Amounts requested in the GRC application** | **Amounts currently authorized for 2013** | **Increase compared to currently athorized amounts** |
|---|---|---|---|
| Electric distribution | $ 4,355 | $ 3,768 | $ 587 |
| Gas distribution | 1,810 | 1,324 | 486 |
| Electric generation | 1,946 | 1,737 | 209 |
| **Total revenue requirements** | **$ 8,111** | **$ 6,829** | **$ 1,282** |

The Utility's 2014 forecast for gas distribution operations includes increased costs to replace 180 miles of distribution line per year (compared to 30 miles currently), use new leak detection technologies and survey the entire system more frequently, remotely monitor and control a significant number of valves, implement an asset management system to provide detailed, readily accessible information about the gas distribution system, and reduce response times for customer gas odor reports. The Utility's forecast for electric distribution operations includes increased costs to upgrade and replace assets to improve safety and reduce outages, use infrared technology to identify and correct equipment issues, install more automation to limit the impact and duration of outages, mitigate wildfire risk, increase system capacity to meet new customer demand, and enhance asset records management and integrate it with key systems. The Utility's forecast for electric generation includes increased costs to operate the Utility's hydroelectric system (including costs related to the Helms pumped storage facility and costs associated with operating licenses issued by the FERC), comply with new requirements adopted by the NRC applicable to the Utility's Diablo Canyon nuclear power plant, and operate and maintain the Utility's fossil fuel-fired and other generating facilities. In addition, the Utility's forecast includes increased costs to improve service at the Utility's local offices and customer contact centers and to improve the service provided by field account representatives to small and mid-sized business customers.

In its application, the Utility has requested that the CPUC establish new balancing accounts to allow the Utility to recover costs associated with gas leak survey and repair work, major emergencies, and new regulatory requirements related to nuclear operations and hydroelectric relicensing, because these costs are subject to a high degree of uncertainty. The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized revenues in 2015 and 2016, primarily to reflect increases in rate base due to capital investments in infrastructure and, to a lesser extent, anticipated increases in wages and other expenses. The Utility also has requested that revenue requirements be adjusted to reflect certain externally driven changes in the Utility's costs, such as changes in franchise fees. The Utility estimates that this mechanism would result in increases in revenue of $492 million in 2015 and an additional $504 million in 2016.

Independent consultants engaged by the SED are reviewing and evaluating certain operational plans underlying the Utility's 2014 cost forecast to ensure that safety and security concerns have been addressed and that the plans properly incorporate risk assessments and mitigation measures. The SED has also engaged independent consultants to conduct a financial audit of the Utility's gas distribution system, which will examine the Utility's authorized and budgeted capital investments and operation and maintenance expenditures for its last two authorized GRC cycles. The SED reports on the results of the consultants' evaluations and financial audit are due May 31, 2013. The Utility and other parties will be able to respond to the reports.

According to the CPUC's current procedural schedule for the proceeding, which may be subject to change in the future, the CPUC's Division of Ratepayer Advocates ("DRA") is scheduled to serve its report on the Utility's application by May 3, 2013. Additional testimony from other parties must be submitted by May 17, 2013. The schedule contemplates evidentiary hearings to be held this summer, followed by a proposed decision to be released in November 2013 and a final CPUC decision to be issued in December 2013. If the decision is delayed, the Utility will, consistent with CPUC practice in prior GRCs, request that the CPUC issue an order directing that the authorized revenue requirement changes be effective January 1, 2014, even if the decision is issued after that date.

**FERC Transmission Owner Rate Case**

On September 28, 2012, the Utility filed an application with the FERC to increase the Utility's retail and wholesale electric transmission customer rates that have been in effect since March 1, 2011. The proposed rate changes will become effective on May 1, 2013, subject to refund following the FERC's issuance of a final decision. The most significant factors driving the requested increase are the Utility's continuing needs to replace and modernize aging electric transmission infrastructure; to interconnect new electric generation, including renewable resources; and to accommodate the magnitude and location of forecasted electric load growth in California. The Utility forecasts that it will make investments of $783 million in 2012 and an additional $837 million in 2013 in various capital projects, including projects to add transmission capacity, expand automation technology, improve overall system reliability, and maintain and replace equipment at substations. The proposed rate base in 2013 is forecast to be $4.5 billion compared to $3.6 billion in 2011. The operations and maintenance costs associated with this request are forecast to be approximately $191 million in 2013, compared to $152 million in 2011.

Compared to present rates, the Utility estimated that revenues would increase by $254 million based on the Utility's requested ROE of 11.5%, for total 2013 electric transmission revenues of $1.2 billion. On November 29, 2012, the FERC issued an order that accepted the Utility's application but directed the Utility to reduce its proposed revenue requirement and rates to reflect the median ROE of a comparative group of other utilities. In response to the FERC's order, on December 21, 2012, the Utility revised its requested revenue requirements and rates to reflect a 9.1% ROE. Based on the reduced ROE, the Utility estimates that revenues would increase by approximately $158 million, for total annual electric transmission revenues of $1.1 billion beginning on May 1, 2013. On December 21, 2012, the Utility also filed a request for rehearing of the FERC's order. It is uncertain when the FERC will act on the request for rehearing. The ultimate resolution of revenue requirements and rates will be addressed through hearings and settlement procedures.

**Energy Efficiency Programs and Incentive Ratemaking**

On December 20, 2012, the CPUC approved a new energy efficiency incentive mechanism to reward the Utility and other California energy utilities for the successful implementation of their 2010-2012 energy efficiency programs. The CPUC awarded the Utility $21 million for the successful implementation of the Utility's 2010 energy efficiency programs. The CPUC decision also established the process that is expected to apply to incentive claims for program years 2011 and 2012. After the CPUC completes its audit of the utilities' 2011 program expenditures, the utilities must file their incentive claims in the third quarter of 2013 for approval by the CPUC in the fourth quarter of 2013. Similarly, the utilities will file their incentive claims based on the CPUC-audited 2012 program expenditures in the third quarter of 2014 for approval by the CPUC in the fourth quarter of 2014.

**Diablo Canyon Nuclear Power Plant**

In March 2012, the NRC issued several orders to the owners of all U.S. operating nuclear reactors to implement the highest-priority recommendations issued by the NRC's task force to incorporate the lessons learned from the March 2011 earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan. Among other directives, the NRC requested nuclear power plant owners to provide additional information about seismic and flooding hazards and emergency preparedness. In response to the orders, the utilities are required to re-evaluate the models used to determine compliance with the license conditions relating to seismic and flooding design. Each nuclear power plant owner will be required to be in full compliance with the NRC orders within two refueling outages or by December 31, 2016, whichever comes first. The Utility has already provided the initially requested information to the NRC and will continue to respond to the NRC orders as required. After reviewing the information submitted by the Utility and other nuclear power plant owners, the NRC may issue further orders which may include facility-specific orders. The Utility will incur costs to comply with Fukushima related NRC orders. The Utility has requested that the CPUC allow the Utility to recover costs incurred in 2014 through 2016 to comply with NRC orders through rates to be authorized by the CPUC in the Utility's 2014 GRC.

The Utility also has filed an application at the NRC to renew the operating licenses for the two operating units at Diablo Canyon which expire in 2024 and 2025. In May 2011, after the Fukushima-Dai-ichi event, the NRC granted the Utility's request to delay processing the Utility's application until certain advanced seismic studies were completed by the Utility. When the Utility began the studies in 2010, it was anticipated that the studies would be completed in 2013 or 2014, depending upon whether required permits were timely obtained from environmental and local government agencies. In November 2012, the California Coastal Commission denied the Utility's request for permits to conduct off-shore three-dimensional high-energy seismic studies, in part, based on the finding that, because the studies were not necessary for NRC compliance, the potential environmental effects did not outweigh the risks. The Utility has completed the data collection phases for the on-shore advanced seismic studies as well as other off-shore low-energy seismic studies. The Utility is assessing whether it has sufficient seismic data without conducting high energy off-shore studies or if other studies are needed. Depending on the outcome of the Utility's assessment, it is uncertain when the Utility would request the NRC to resume the relicensing proceeding. In order to receive renewed operating licenses, the Utility also must undergo a consistency review by the California Coastal Commission. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel which is not expected to be issued before September 2014. The NRC has stated that it will not take action in licensing or re-licensing proceedings until it issues a new "waste confidence decision." (See "Risk Factors" below.)

Finally, the CPUC is also considering the Utility's application to recover estimated costs to decommission the Utility's nuclear facilities at Diablo Canyon and the retired nuclear facility located at the Utility's Humboldt Bay Generation Station. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover the estimated costs through rates. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennal Proceeding in Note 2 of the Notes to the Consolidated Financial Statements.)

## Other Matters

### *Electric Distribution Facilities*

The Utility conducted a system-wide review of its patrol and inspection records for underground and overhead electric distribution facilities after the Utility reported to the CPUC in July 2012 that some of the Utility's facilities were not patrolled and/or inspected at the periodic intervals required by the CPUC's rules. The Utility concluded a system-wide review and found that approximately 0.4% of its total electric distribution facilities had not been patrolled and/or inspected at the intervals required by CPUC rules. The Utility has submitted the results of its review to the SED and has completed the patrols and inspections of all such facilities.

In October 2012, the Utility also reported to the CPUC that it planned to re-inspect electric distribution underground and overhead facilities that had been identified as inspected by a contractor after a review determined that the inspection practices used by some of the contractor's employees did not meet the Utility's standards. The re-inspections have been completed.

PG&E Corporation and the Utility are uncertain how the above matters will affect the other regulatory proceedings and current investigations involving the Utility, or whether additional proceedings or investigations will be commenced that could result in regulatory orders or the imposition of penalties on the Utility.

### *Residential Rate Design*

In June 2012, the CPUC opened a rulemaking proceeding to examine electric rate design for residential customers among California's electric utilities and consider regulatory and legislative changes that may be needed to the current rate structure. PG&E Corporation and the Utility are uncertain how the outcome of this rulemaking proceeding will affect the Utility's future electric rate structure.

## ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. (See "Risk Factors" below.) These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel.

## Remediation

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant ("MGP") sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. (See Note 15 of the Notes to the Consolidated Financial Statements.)

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor sites. The Utility is also required to take measures to abate the effects of the contamination on the environment. At the Hinkley natural gas compressor site, the Utility's remediation and abatement efforts are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region ("Regional Board"). The Regional Board has issued several orders directing the Utility to implement interim remedial measures to reduce the mass of the underground plume of hexavalent chromium, monitor and control movement of the plume, and provide replacement water to affected residents.

The Utility submitted its proposed final remediation plan to the Regional Board in September 2011 recommending a combination of remedial methods to clean up groundwater contamination, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated the Utility's proposed methods and the potential environmental impacts. The Utility expects that the Regional Board will consider certification of the final EIR in the second quarter of 2013. Following certification of the EIR, the Regional Board is expected to issue the final cleanup standards.

The Regional Board ordered the Utility in October 2011 to provide an interim and permanent replacement water system for resident households located near the chromium plume that have domestic wells containing hexavalent chromium in concentrations greater than 0.02 parts per billion. The Utility filed a petition with the California State Water Resources Control Board ("California Water Board") to contest certain provisions of the order. In June 2012, the Regional Board issued an amended order to allow the Utility to implement a whole house water replacement program for resident households located near the chromium plume boundary. Eligible residents may decide whether to accept a replacement water supply or have the Utility purchase their properties, or alternatively not participate in the program. As of January 31, 2013, approximately 350 residential households are covered by the program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to complete implementation of the whole house water replacement systems by August 31, 2013. The Utility will maintain and operate the whole house replacement systems for five years or until the State of California has adopted a drinking water standard specifically for hexavalent chromium at which time the program will be evaluated.

At December 31, 2012 and 2011, $226 million and $149 million, respectively, were accrued in PG&E Corporation's and the Utility's Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. The increase primarily reflects the Utility's best estimate of costs associated with the developments described above. Remediation costs for the Hinkley natural gas compressor site are not recovered from customers through rates. Future costs will depend on many factors, including the Regional Board's certification of the final EIR **,** the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the Utility's required time frame for remediation, and adoption of a final drinking water standard currently under development by the State of California, as mentioned above. As more information becomes known regarding these factors, these estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions may have a material impact on PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows.

**Climate Change**

A report issued in 2012 by the U.S. Environmental Protection Agency ("EPA") entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. (See "Risk Factors" below.) Although no comprehensive federal legislation has been enacted to address the reduction of GHG emissions, the California legislature has taken action to address climate change.

***GHG Cap-and-Trade***

The California Global Warming Solutions Act of 2006 (also known as California Assembly Bill 32 or AB 32) requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The California Air Resources Board ("CARB") is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB has approved various regulations, including regulations that established a state-wide, comprehensive "cap-and-trade" program that sets a gradually declining limit (or "cap") on the amount of GHGs that may be emitted by the major sources of GHG emissions each year. The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020. Emitters may meet up to 8% of their compliance obligation through the purchase of "offset credits" which represent GHG emissions abatement achieved in sectors that are not subject to the cap.

Each year the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters (also known as covered entities) are required to obtain and surrender allowances equal to the amount of their GHG emissions within a particular compliance period. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges on the secondary market for trading GHG allowances. The CARB's first quarterly auction was held on November 14, 2012.

Also, during each year of the program, the CARB will allocate a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their auction revenues, including accrued interest, among certain classes of their electricity distribution customers in accordance with existing state law. Although the CPUC had previously authorized the utilities to recover their GHG compliance costs through rates, the CPUC decided that the recovery of GHG compliance costs should be deferred until the CPUC adopted a final auction revenue allocation methodology. Until a final methodology is adopted, the utilities have been ordered to track GHG costs and auction revenues for future rate recovery. (See Note 3 of the Notes to the Consolidated Financial Statements.) The CARB has not yet decided whether and to what extent allowances will be freely allocated to regulated gas utilities for the benefit of their natural gas customers starting in the second compliance period beginning in 2015.

The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

### *Renewable Energy Resources*

California's Renewables Portfolio Standard ("RPS") program increases the amount of renewable energy that load-serving entities, such as the Utility, must deliver to their customers from at least 20% of their total retail sales, as required by the prior law, to 33% of their total retail sales. The RPS program, which became effective in December 2011, established compliance periods: 2011 through 2013, 2014 through 2016, 2017 through 2020, and 2021 and thereafter. The RPS compliance requirement that must be met for each of these compliance periods will gradually increase through 2020 and will be determined on an annual basis thereafter. In June 2012, the CPUC adopted rules for transitioning between the prior 20% RPS program and the 33% RPS program, applying excess procurement quantities across compliance periods, using procurement from short-term contracts to meet compliance requirements, and reporting annual RPS compliance to the CPUC.

The Utility has made substantial financial commitments under third-party renewable energy contracts to meet RPS procurement quantity requirements. (See Note 15 of the Notes to the Consolidated Financial Statements.) The Utility currently forecasts that it will comply with its procurement requirements. The costs incurred by the Utility under third-party contracts to meet RPS requirements are expected to be recovered with other procurement costs through rates. The costs of Utility-owned renewable generation projects will be recoverable through traditional cost-of-service ratemaking mechanisms provided that costs do not exceed the maximum amounts authorized by the CPUC for the respective project.

### Water Quality

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. The EPA is required to issue final regulations by July 2013.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The California Water Board has appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at nuclear power plants. The committee's assessment is due by October 2013. If the California Water Board does not require the installation of cooling towers at Diablo Canyon, the Utility could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

## LEGAL MATTERS

In addition to the provisions made for contingencies related to the San Bruno accident, PG&E Corporation's and the Utility's Consolidated Financial Statements also include provisions for claims and lawsuits that have arisen in the ordinary course of business, regulatory proceedings, and other legal matters. (See "Legal and Regulatory Contingencies" in Note 15 of the Notes to the Consolidated Financial Statements.)

## OFF-BALANCE SHEET ARRANGEMENTS

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 2 (PG&E Corporation's tax equity financing agreements) and Note 15 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements).

## RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

On July 21, 2010, President Obama signed into law federal financial reform legislation, the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). PG&E Corporation and the Utility are implementing programs to comply with the final regulations that have been issued pursuant to Dodd-Frank.

### Commodity Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk.

The Utility uses value-at-risk to measure its shareholders' exposure to price and volumetric risks resulting from variability in the price of, and demand for, natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 95% confidence level, which means that there is a 5% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk uses market data to quantify the Utility's price exposure. When market data is not available, the Utility uses historical data or market proxies to extrapolate the required market data. Value-at-risk as a measure of portfolio risk has several limitations, including, but not limited to, inadequate indication of the exposure to extreme price movements and the use of historical data or market proxies that may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately $13 million and $11 million at December 31, 2012 and 2011, respectively. During the 12 months ended December 31, 2012, the Utility's approximate high, low, and average values-at-risk were $13 million, $10 million and $12 million, respectively. And during 2011, the value-at-risk amounts were $11 million, $7 million and $9 million, respectively. (See Note 10 of the Notes to the Consolidated Financial Statements for further discussion of price risk management activities.)

### Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2012 and December 31, 2011, if interest rates changed by 1% for all current PG&E Corporation and Utility variable rate and short-term debt and investments, the change would affect net income for the next 12 months by $7 million and $13 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

**Energy Procurement Credit Risk**

The Utility conducts business with counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility ties many energy contracts to master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's net credit risk exposure to its counterparties, as well as the Utility's credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as of December 31, 2012 and December 31, 2011:

| (in millions) | Gross Credit Exposure Before Credit Collateral [(1)] | Credit Collateral | Net Credit Exposure [(2)] | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| December 31, 2012 | $ 94 | $ (9) | $ 85 | 2 | 62 |
| December 31, 2011 | 151 | (13) | 138 | 2 | 106 |

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.

(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

## CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

**Regulatory Assets and Liabilities**

The Utility's rates are primarily set by the CPUC and the FERC and are designed to recover the cost of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods that the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, the Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other reduction of net allowable costs be given to customers over future periods.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied during 2012, 2011, and 2010, the recovery of any material costs previously recognized by the Utility as regulatory assets.

If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. At December 31, 2012, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $8.3 billion and regulatory liabilities (including current balancing accounts payable) of $6.1 billion.

**Loss Contingencies**

***Environmental Remediation Liabilities***

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former MGP sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former MGP sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2012 and 2011, the Utility's accruals for undiscounted gross environmental liabilities were $910 million and $785 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.6 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Legal and Regulatory Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are subject to claims or named as parties in lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the minimum amount, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amount of such losses, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs. (See "Legal and Regulatory Contingencies" in Note 15 of the Notes to the Consolidated Financial Statements.)

**Asset Retirement Obligations**

PG&E Corporation and the Utility account for an asset retirement obligation ("ARO") at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. A legal obligation can arise from an existing or enacted law, statute, or ordinance; a written or oral contract; or under the legal doctrine of promissory estoppel.

At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process.

Most of PG&E Corporation's and the Utility's AROs relate to the Utility's obligation to decommission its nuclear generation facilities and certain fossil fuel-fired generation facilities. The Utility estimates its obligation for the future decommissioning of its nuclear generation facilities and certain fossil fuel-fired generation facilities. In December 2012, the Utility submitted an updated estimate of the cost to decommission its nuclear facilities to the CPUC. The increase in the estimated obligation of $1.3 billion was primarily due to higher spent nuclear fuel disposal costs and an increase in the scope of work. To estimate the liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation. (See Note 2 of the Notes to the Consolidated Financial Statements.)

Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. Additionally, if the inflation adjustment increased 25 basis points, the amount of the ARO would increase by approximately 1.57%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 4.03%. At December 31, 2012, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $2.9 billion.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees.

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant a ctuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

PG&E Corporation and the Utility recognize the funded status of their respective plans on their respective Consolidated Balance Sheets with an offsetting entry to accumulated other comprehensive income (loss); or, to the extent that the cost of the plans are recoverable in utility rates, to regulatory assets and liabilities, resulting in no impact to their respective Consolidated Statements of Income.

Pension and other benefit expense is based on the differences between actuarial assumptions and actual plan results and is deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. (See Note 3 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation and the Utility review recent cost trends and projected future trends in establishing health care cost trend rates. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2012 is 7.5%, gradually decreasing to the ultimate trend rate of 5% in 2018 and beyond.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 5.4% compares to a ten-year actual return of 10.2%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 648 Aa-grade non-callable bonds at December 31, 2012. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2012 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2012 |
|---|---|---|---|
| Discount rate | (0.50) % | $ 110 | $ 1,262 |
| Rate of return on plan assets | (0.50) % | 54 | - |
| Rate of increase in compensation | 0.50% | 50 | 308 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2012 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2012 |
|---|---|---|---|
| Health care cost trend rate | 0.50 % | $ 4 | $ 53 |
| Discount rate | (0.50) % | 2 | 132 |
| Rate of return on plan assets | (0.50) % | 7 | - |

**RISK FACTORS**

***PG&E Corporation's and the Utility's reputations have been significantly affected by the negative publicity surrounding the San Bruno accident, the related investigations and civil litigation, and the various reports the Utility has submitted to the CPUC to disclose noncompliance with applicable regulations. Their reputations may be further adversely affected by publicity regarding developments in the pending CPUC and criminal investigations, and by future investigations or other regulatory or governmental proceedings that may be commenced, and by media or public scrutiny of the Utility's electricity and natural gas operations. Such further reputational harm or the inability of PG&E Corporation and the Utility to restore their reputations may further affect their financial conditions, results of operations and cash flows.***

The reputations of PG&E Corporation and the Utility have seriously suffered as a result of the San Bruno accident for which the Utility has acknowledged liability; the June 2011 investigative report from the CPUC's independent review panel and the August 2011 National Transportation Safety Board ("NTSB") report, both of which criticized the Utility's safety recordkeeping for its natural gas transmission system and the Utility's pipeline installation, integrity management, and other operational practices; and the media coverage of the accident and the related investigations and lawsuits. After the San Bruno accident, the CPUC initiated three investigations pertaining to the Utility's natural gas transmission pipeline operations, including an investigation of the San Bruno accident. (See "Natural Gas Matters" above.) A criminal investigation of the San Bruno accident also has been commenced. The media also has widely reported on the civil lawsuits arising from the San Bruno accident which seek compensation and punitive damages for personal injuries, deaths, and property damage.

In addition, the Utility has notified the SED of various self-identified violations of regulations applicable to natural gas safety and operating practices since December 2011 when the CPUC imposed the self-reporting requirement and authorized the SED to impose penalties based on the self-identified violations. In January 2012, the SED imposed penalties of $17 million on the Utility for self-reported failure to perform certain leak surveys and the SED may impose additional penalties based on other self-reported violations. These self-reports also have received negative media attention.

The Utility's operations are also subject to heightened and well-publicized concerns about many aspects of its operations, such as the Utility's nuclear generation operations at Diablo Canyon and the risks of terrorist acts, earthquakes, or a nuclear accident; the Utility's environmental remediation activities; and the accuracy, privacy, and safety of the Utility's information and operating systems, including those used to measure customer energy usage and generate bills. These concerns have often led to additional adverse media coverage and could later result in investigations or other action by regulators, legislators and law enforcement officials or in lawsuits.

Further, these concerns may cause investors to question management's ability to repair the reputational harm that PG&E Corporation and the Utility have suffered, resulting in an adverse impact on the market price of PG&E Corporation common stock. Given PG&E Corporation's and the Utility's greater equity needs, a declining stock price would cause further dilution in net income per share. The extent to which their reputations can be restored will depend, in part, on the success of the Utility's efforts to improve the safety and reliability of the natural gas system as planned in the Utility's pipeline safety enhancement plan, whether they can respond to the findings and recommendations made by the CPUC's independent review panel and the NTSB, and whether they are able to adequately convince regulators, legislators, law enforcement officials, the media and the public that they have done so. Their ability to repair their reputations also may be affected by developments that may occur in the pending investigations, including the amount of civil or criminal penalties that may be imposed on the Utility; whether there are new investigations or citations; and developments that may occur in the San Bruno accident-related civil litigation. If PG&E Corporation and the Utility are unable to repair their reputations, their financial conditions, results of operations and cash flows may be further negatively affected.

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected by the ultimate amount of penalties imposed on the Utility; the costs of taking required remedial actions; the ultimate amount of criminal penalties, if any, imposed by governmental authorities; and the ultimate amount of third–party liability arising from the San Bruno accident and the availability, timing and amount of related insurance recoveries.***

The CPUC has stated that it is prepared to impose substantial penalties on the Utility in connection with the investigations. Although the parties have engaged in settlement discussions in an effort to reach a stipulated outcome to resolve the investigations, the parties have not reached an agreement. If a stipulated outcome is not reached and the CPUC issues a decision that finds that the Utility violated applicable laws, rules or orders, the CPUC can impose penalties of up to $20,000 per day, per violation. (For violations that are considered to have occurred on or after January 1, 2012, the statutory penalty has increased to a maximum of $50,000 per day, per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this discretion in determining penalties. The SED also has this discretion under the authority delegated to it by the CPUC, but the SED is required to impose the maximum statutory penalty per violation, per day.

PG&E Corporation and the Utility have concluded that it is probable that the Utility will be required to pay penalties in connection with the investigations and potential SED enforcement related to the self-reports and have accrued an amount in their financial statements that reflects the reasonably estimable minimum amount of penalties they believe it is probable that the Utility will incur. After considering the many variables that could affect the ultimate amount of penalties the Utility may be required to pay, PG&E Corporation and the Utility are unable to make a better estimate of the probable loss or estimate the reasonably possible amount of penalties that the Utility could incur in excess of the amount accrued and such amount could be material. In addition to penalties, the Utility could incur significant costs to implement any remedial actions the CPUC may order the Utility to perform.

PG&E Corporation and the Utility also are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any criminal penalties that may be imposed in connection with the pending criminal investigation. Any civil or criminal penalties imposed on the Utility will not be recoverable from customers. (See Note 15 of the Notes to the Consolidated Financial Statements.) PG&E Corporation and the Utility also have concluded that it is probable that the Utility will incur a loss in connection with the lawsuits arising from the San Bruno accident and have accrued an amount in their financial statements for the reasonably estimable minimum amount of loss. PG&E Corporation and the Utility believe that a significant portion of the third-party liabilities the Utility incurs will be recoverable through insurance, but there is a risk that the insurers could deny coverage for claims under the terms of the policies, deem settlement amounts excessive and not payable, or be financially unable to pay the Utility's claims. Further, although many of the San Bruno lawsuits have been settled, a substantial number of cases are unresolved and plaintiffs continue to pursue compensatory and punitive damages. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any punitive damages that could be awarded to plaintiffs in the civil litigation. (See Note 15 of the Notes to the Consolidated Financial Statements.)

The estimates and assumptions underlying the accrued amounts and the ultimate amount of penalties and third-party losses are subject to change based on the amount of penalties actually imposed by the CPUC or agreed to in a stipulated outcome that may be reached to resolve the investigations, by the outcome of trials in the San Bruno litigation, and the terms of additional settlement agreements that may be reached with remaining plaintiffs. Future changes to estimates and assumptions could result in additional accruals in future periods which could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations in the period in which they are recognized.

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been, and will continue to be, materially affected by costs incurred by the Utility to perform work under its pipeline safety enhancement plan, to undertake other pipeline-related work, and to improve the safety and reliability of its natural gas and electricity operations.***

Although the CPUC approved most of the proposed scope and timing of projects under the Utility's pipeline safety enhancement plan, the CPUC disallowed the Utility's request for rate recovery of a significant portion of capital costs and expenses through 2014, including costs of pressure testing pipelines placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC may disallow additional costs based on the final results of the Utility's pipeline records search and pipeline pressure validation work, which the Utility expects to complete by May 2013. (See "Natural Gas Matters" above.) The Utility will be unable to recover any costs in excess of the adopted capital and expense amounts and the adopted amounts will be reduced by the cost of any plan project not completed during the first phase and not replaced with a higher priority project. Further, actual costs for 2013 and 2014 may be materially higher than the Utility currently forecasts. During 2013, the Utility expects to request that the CPUC approve the proposed timing, scope and cost recovery for the first three years (2015, 2016, and 2017) of the second phase of the plan beginning on January 1, 2015. While the Utility's request will include updated cost forecasts based on the Utility's experience during the first phase, there is some risk that categories of costs that were disallowed by the CPUC in its decision on the first phase also will be disallowed in the second phase.

In addition, the Utility forecasts that it will incur additional costs outside of the scope of the pipeline safety enhancement plan in 2013 and 2014 that are not expected to be recoverable through rates. This includes costs to establish the parameters of the Utility's "rights-of-way" surrounding pipelines and to identify and remove encroachments from these pipeline rights-of-way. The Utility also forecasts it will continue to incur additional costs associated with the integrity of transmission pipelines, conduct other gas-related work, and legal and regulatory expenses. The Utility also forecasts that it will incur costs to improve electric and gas distribution operations in 2013 that exceed the amounts assumed when rates were set in the last rate cases. (See "Operating and Maintenance" above.) Actual costs may be materially higher than forecast. Further, as the Utility continues to review its natural gas system and operating practices and as industry practices and standards evolve, the Utility may undertake additional work in the future to improve the safety and reliability of its natural gas utility services, for example, to validate the maximum allowable operating pressure of other facilities in its natural gas transmission system, such as compressor stations. The Utility may be unable to recover the costs of such additional work through rates. The Utility also may incur third-party liability related to service disruptions caused by changes in pressure on its natural gas transmission system as work is performed.

***PG&E Corporation's and the Utility's financial condition depends upon the Utility's ability to recover its operating expenses and its electricity and natural gas procurement costs and to earn a reasonable rate of return on capital investments, in a timely manner from the Utility's customers through regulated rates.***

The Utility's ability to recover its costs and earn its authorized rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers' rates and differences between the forecast or authorized costs embedded in rates (which are set on a prospective basis) and the amount of actual costs incurred. (See "Regulatory Matters – 2014 General Rate Case" above.) The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. For example, the CPUC has prohibited the Utility from recovering a material portion of costs that the Utility has already incurred, and will continue to incur, as it performs work under the pipeline safety enhancement plan, in part, because the CPUC found that such costs were incurred as a result of imprudent management. The CPUC may order the Utility to propose cost-sharing methods for certain costs or the Utility may decide for other reasons not to seek recovery of certain costs. In either case, the Utility would incur costs that are not recovered through rates. (See "Natural Gas Matters" above.)

Further, to serve its customers in a safe and reliable manner, the Utility may be required to incur expenses before the CPUC approves the recovery of such costs. The Utility is generally unable to recover costs incurred before CPUC authorization is obtained, unless the CPUC authorizes the Utility to track costs for potential future recovery. For example, the Utility requested that the CPUC allow the Utility to track costs incurred in 2012 under the pipeline safety enhancement plan before the CPUC approved the plan. The CPUC did not address the Utility's request and as a result the Utility was unable to recover costs incurred before the effective date of the decision, December 20, 2012. The Utility's failure to recover these and other pipeline-related costs has materially affected PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

Fluctuating commodity prices, changes in laws and regulations or changes in the political and regulatory environment also may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. Current law and regulatory mechanisms permit the Utility to pass through its costs to procure electricity and natural gas to customers in rates. A significant and sustained rise in commodity prices, caused by costs associated with new renewable energy resources and California's new cap-and-trade program and other factors, could create overall rate pressures that make it more difficult for the Utility to recover its costs. This pressure could increase as the Utility continues to collect authorized rates to support public purpose programs, such as energy efficiency programs, and low-income rate subsidies, and to fund customer incentive programs. Further, current California law restricts the ability of the CPUC to adjust electricity rates for certain customer classes which could lead to a perception that some customers are unfairly subsidizing other customers and that some commercial customers are competitively disadvantaged as compared to similar customers in other states. The customer concerns caused by these perceived inequities could also make it more difficult for the Utility to recover its operational costs.

The Utility's ability to recover its costs also may be affected by the economy and the economy's corresponding impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base. A portion of the Utility's revenues depends on the level of customer demand for the Utility's natural gas transportation services which can fluctuate based on economic conditions, the price of natural gas, and other factors.

The Utility's failure to recover its operating expenses, including electricity and natural gas procurement costs in a timely manner through rates could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

***The Utility's ability to procure electricity to meet customer demand at reasonable prices and recover procurement costs timely may be affected by increasing renewable energy requirements, the continuing functioning of the wholesale electricity market in California, and the new cap-and-trade market.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the principles of "least cost dispatch."

The Utility enters into power purchase agreements, including contracts to purchase renewable energy, in compliance with a long-term procurement plan approved by the CPUC. The Utility executes power purchase agreements following competitive requests for offers. The Utility submits the winning contracts to the CPUC for approval and authorization to recover contract costs through rates. There is a risk that the contractual prices the Utility is required to pay will become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to economic conditions or the loss of the Utility's customers to other generation providers. In particular, as the market for renewable energy develops in response to California's renewable energy requirements, there is a risk that the Utility's contractual commitments could result in procurement costs that are higher than the market price of renewable energy. This could create a further risk that, despite original CPUC approval of the contracts, the CPUC would disallow contract costs in the future if the CPUC determines that the costs are unreasonably above market. In addition, the CPUC could disallow procurement costs if the CPUC determined that the Utility incurred procurement costs that were not in compliance with its CPUC-approved procurement plan, or that the Utility did not prudently administer the power purchase agreements that were executed in compliance with the plan. The Utility also purchases energy through the day-ahead wholesale electricity market operated by the California Independent System Operator ("CAISO"). The amount of electricity the Utility purchases on the wholesale market fluctuates due to a variety of factors, including, the level of electricity generated by the Utility's own generation facilities, changes in customer demand, periodic expirations or terminations of power purchase contracts, the execution of new power purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, and the implementation of new energy efficiency and demand response programs. The market prices of electricity also fluctuate. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended, which could result in excessive market prices. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

In addition, with the beginning of the first compliance period under the new California cap-and-trade regulations on January 1, 2013, electricity costs include associated cap-and-trade compliance costs. Although some of these costs will be offset by revenues from the sale of emission allowances by the Utility on behalf of some classes of electricity customers, it is uncertain how the cap-and-trade market will develop in the future especially as the cap-and-trade compliance periods expand to cover other sources of GHG emissions and as other regional or federal cap-and-trade programs are adopted.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected if the Utility is unable to recover a material portion of the costs it incurs to deliver electricity to customers.

***The completion of capital investment projects is subject to substantial risks, and the timing of the Utility's capital expenditures and recovery of capital-related costs through rates, if at all, will directly affect net income.***

The Utility's ability to invest capital in its electric and natural gas businesses is subject to many risks, including risks related to obtaining regulatory approval, securing adequate and reasonably priced financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party contractors on which the Utility depends to develop or construct these projects also face many of these risks. Changes in tax laws or policies, such as those relating "bonus" depreciation, may also affect when or whether a potential project is developed. In addition, reduced forecasted demand for electricity and natural gas as a result of an economic slow-down, or other reasons, may also increase the risk that projects are deferred, abandoned, or cancelled. Some of the Utility's future capital investments may also be affected by evolving federal and state policies regarding the development of a "smart" electric transmission grid.

In addition, differences in the amount or timing of actual capital expenditures compared to the amount and timing of forecast capital expenditures authorized to be recovered through rates, can directly affect net income. Further, if capital expenditures are disallowed, the Utility would be required to write-off such expenses which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations.

***PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth due to municipalization, an increase in the number of community choice aggregators, increasing levels of "direct access," and the development and integration of self-generation and distributed generation technologies, if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility's customers could bypass its distribution and transmission system by obtaining such services from other providers. This may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers. In addition, local government agencies could exercise their power of eminent domain to acquire the Utility's facilities and use the facilities to provide utility service to their local residents and businesses. The Utility may be unable to fully recover its investment in the distribution assets that it no longer owns. The Utility's natural gas transmission facilities could be bypassed by interstate pipeline companies that construct facilities in the Utility's markets, by customers who build pipeline connections that bypass the Utility's natural gas transmission and distribution system, or by customers who use and transport liquefied natural gas.

Alternatively, the Utility's customers could become direct access customers who purchase electricity from alternative energy suppliers or they could become customers of governmental bodies registered as community choice aggregators to purchase and sell electricity for their residents and businesses. Although the Utility is permitted to collect a non-bypassable charge for generation-related costs incurred on behalf of these customers, or distribution, metering, or other services it continues to provide, the fee may not be sufficient for the Utility to fully recover the costs to provide these services. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, could put upward rate pressure on remaining customers. Also, a confluence of technology-related cost declines and sustained federal or state subsidies make a combination of distributed generation and storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments.

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, increasing self-generation and net energy metering, and the growth of distributed generation, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

***The operation of the Utility's electricity and natural gas generation, transmission, and distribution facilities involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial condition, results of operations and cash flows, and the Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. The Utility's service territory covers approximately 70,000 square miles in northern and central California and is composed of diverse geographic regions with varying climates and weather conditions that create numerous operating challenges. The Utility's facilities are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The Utility's ability to earn its authorized rate of return depends on its ability to efficiently maintain and operate its facilities and provide electricity and natural gas services safely and reliably. The maintenance and operation of the Utility's facilities, and the facilities of third parties on which the Utility relies, involve numerous risks, including the risks discussed elsewhere in this section and those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;
- the failure of generation facilities to perform at expected or at contracted levels of output or efficiency;
- the failure of a large dam or other major hydroelectric facility;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event;
- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wildland and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;
- operator or other human error;
- fuel supply interruptions or the lack of available fuel which reduces or eliminates the Utility's ability to provide electricity and/or natural gas service;
- the release of hazardous or toxic substances into the air or water;
- use of new or unproven technologies;
- cyber-attack; and
- acts of terrorism, vandalism, or war.

The occurrence of any of these events could affect demand for electricity or natural gas; cause unplanned outages or reduce generating output which may require the Utility to incur costs to purchase replacement power; cause damage to the Utility's assets or operations requiring the Utility to incur unplanned expenses to respond to emergencies and make repairs; damage the assets or operations of third parties on which the Utility relies; subject the Utility to claims by customers or third parties for damages to property, personal injury, or wrongful death, or subject the Utility to penalties. These costs may not be recoverable through rates or insurance. Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage or may not be available at all.

***The Utility's operational and information systems on which it relies to conduct its business and serve customers could fail to function properly due to technological problems, a cyber-attack, acts of terrorism, severe weather, a solar event, an electromagnetic event, a natural disaster, the age and condition of information technology assets, human error, or other reasons, that could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense.***

The operation of the Utility's extensive electricity and natural gas systems rely on evolving information and operational technology systems and network infrastructures that are becoming more complex as new technologies and systems are implemented to modernize capabilities to safely and reliably deliver gas and electric services. The Utility's business is highly dependent on its ability to process and monitor, on a daily basis, a very large number of tasks and transactions, many of which are highly complex. The failure of the Utility's information and operational systems and networks could significantly disrupt operations; result in public and employee safety lapse; result in outages; reduced generating output; damage to the Utility's assets or operations or those of third parties; and subject the Utility to claims by customers or third parties, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require constant maintenance, modification, and updating, which can be costly and increases the risk of errors and malfunction. Any disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification or implementation of new systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively affect the effectiveness of the companies' control environment, and/or the companies' ability to timely file required regulatory reports.

The Utility's ability to measure customer energy usage and generate bills depends on the successful functioning of the advanced metering system. The Utility relies on third party contractors and vendors to service, support, and maintain certain proprietary functional components of the advanced metering system. If such a vendor or contractor ceased operations, if there was a contractual dispute or a failure to renew or negotiate the terms of a contract so that the Utility becomes unable to continue relying on such a third-party vendor or contractor, then the Utility could experience costs associated with disruption of billing and measurement operations and would incur costs as it seeks to find other replacement contractors or vendors or hire and train personnel to perform such services.

Despite implementation of security and mitigation measures, all of the Utility's technology systems are vulnerable to disability or failures due to cyber-attacks, viruses, human errors, acts of war or terrorism, and other events. If the Utility's information technology systems or network infrastructure were to fail, the Utility might be unable to fulfill critical business functions and serve its customers, which could have a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.

In addition, in the ordinary course of its business, the Utility collects and retains sensitive information including personal identification information about customers and employees, customer energy usage, and other information. The theft, damage, or improper disclosure of sensitive electronic data can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, and harm the Utility's reputation.

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility's workforce is aging and many employees will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may not be successful. The Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. The terms of these agreements affect the Utility's labor costs. It is possible that labor disruptions could occur. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future. It is also possible that PG&E Corporation and the Utility may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the San Bruno accident. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities that it may not be able to recover from its insurance or other sources, and the Utility may incur significant capital expenditures and compliance costs that it may be unable to fully recover, adversely affecting PG&E Corporation's and the Utility's s financial conditions, results of operations, and cash flows.***

The operation of the Utility's nuclear generation facilities expose it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. There are also significant uncertainties related to the regulatory, technological, and financial aspects of decommissioning nuclear generation plants when their licenses expire. To reduce the Utility's financial exposure to these risks, the Utility maintains insurance and manages decommissioning trusts that hold nuclear decommissioning charges collected through customer rates. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of its nuclear power plants could exceed the amount of the Utility's insurance coverage and nuclear decommissioning trust assets. The Utility has insurance coverage for property damages and business interruption losses, as well as coverage for acts of terrorism at its nuclear power plants as a member of Nuclear Electric Insurance Limited ("NEIL"), a mutual insurer owned by utilities with nuclear facilities. NEIL provides coverage for both nuclear (meaning that nuclear material is released) and non-nuclear losses. Due to multiple large non-nuclear losses in the industry, NEIL has notified the Utility and the other NEIL members that it will be significantly reducing its coverage for non-nuclear losses. This change will affect the Utility beginning in April 2013. While the Utility is seeking alternative insurance options, efforts to obtain additional coverage may not be successful. Even if the Utility is able to obtain additional coverage, this future insurance coverage is not likely to be available at rates and on terms as favorable as the rates and terms of the Utility's current NEIL insurance coverage. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

In addition, as an operator of the two operating nuclear reactor units at Diablo Canyon, the Utility may be required under federal law to pay up to $235 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 15 of the Notes to the Consolidated Financial Statements.) The Utility's ability to continue to operate its nuclear generation facilities also is subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable.

The NRC oversees the licensing, construction, and decommissioning of nuclear facilities and has broad authority to impose requirements relating to the maintenance and operation of nuclear facilities; the storage, handling and disposal of spent fuel; and the safety, radiological, environmental, and security aspects of nuclear facilities. The NRC has adopted regulations that are intended to protect nuclear facilities, nuclear facility employees, and the public from potential terrorist and other threats to the safety and security of nuclear operations, including threats posed by radiological sabotage or cyber-attack. The Utility incurs substantial costs to comply with these regulations. In addition, in March 2012, the NRC issued several orders to the owners of all U.S. operating nuclear reactors to implement the highest-priority recommendations issued by the NRC's task force to incorporate the lessons learned from the March 2011 earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan. The NRC may issue further orders to implement the recommendations, including facility-specific orders, which could require the Utility to incur additional costs.

The Utility has filed an application at the NRC to renew the operating licenses for the two operating units at Diablo Canyon which expire in 2024 and 2025. In May 2011, after the Fukushima-Dai-ichi event, the NRC granted the Utility's request to delay processing the Utility's application until certain advanced seismic studies that the CPUC ordered the Utility to conduct were completed. In November 2012, the California Coastal Commission denied the Utility's request for permits to conduct some of these advanced studies. The Utility is assessing whether it has sufficient seismic data without conducting the high energy off-shore studies or if other studies are needed. It is uncertain when the Utility would request the NRC to resume the relicensing proceeding. In order to receive renewed operating licenses, the Utility also must undergo a sufficiency review by the California Coastal Commission. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel. The NRC's original "waste confidence decision" in which the NRC found that spent nuclear fuel can be safely managed until a permanent off-site repository is established, was successfully challenged on the basis that the NRC's environmental review was deficient. In August 2012, the NRC ruled that it will not issue final decisions in licensing or re-licensing proceedings, including the Utility's re-licensing application, until it had reconsidered the waste confidence issues. The NRC stated that it would consider all available options for resolving the waste confidence issue, which could include generic or site-specific NRC actions, or some combination of both. The NRC has instructed its staff to develop and issue a new waste confidence decision and temporary storage rule by September 2014.

The CPUC has authority to determine the rates the Utility can collect to recover its nuclear fuel, operating, maintenance, compliance, and decommissioning costs. The Utility also could incur significant expense to comply with regulations or orders the NRC may issue in the future to impose new safety requirements, to obtain license renewal, and to comply with federal and state policies and regulations applicable to the use of cooling water intake systems at generation facilities, such as Diablo Canyon. (See "Environmental Matters" above.) The Utility expects that it would seek rate recovery of these additional costs. The outcome of these rate proceedings at the CPUC can be influenced by public and political opposition to nuclear power. If the Utility were unable to recover costs related to its nuclear facilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations at Diablo Canyon. Alternatively, the NRC may order the Utility to cease its nuclear operations until it can comply with new regulations or orders. Further, the Utility could fail to obtain renewed operating licenses for Diablo Canyon requiring nuclear operations to cease when the current licenses expire in 2024 and 2025.

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility can incur significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. These costs can be difficult to forecast because the extent of contamination may be unknown. For example, the Utility's costs to perform hydrostatic pressure testing of natural gas pipelines have included costs to obtain local agency and environmental permits to conduct the tests as well as costs to treat and dispose of the water used in the tests that becomes contaminated as the water travels through the pipes. Further, even if the extent of contamination is known, remediation costs can be difficult to estimate due to many factors, including which remediation alternatives will be used, the applicable remediation levels, and the financial ability of other potentially responsible parties. Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal penalties or other sanctions.

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites, some of which the Utility no longer owns, include former manufactured gas plant sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. (See Note 15 to the Notes to the Consolidated Financial Statements for more information.)

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Further, the CPUC has ruled that the Utility's environmental costs for certain sites, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through this ratemaking mechanism. The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows. (See "Environmental Matters" above.)

***The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.***

A report issued in 2012 by the EPA entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. In December 2009, the EPA issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. The impact of events or conditions caused by climate change could range widely, from highly localized to worldwide, and the extent to which the Utility's operations may be affected is uncertain. For example, if reduced snowpack decreases the Utility's hydroelectric generation, the Utility will need to acquire additional generation from other sources. Under certain circumstances, the events or conditions caused by climate change could result in a full or partial disruption of the ability of the Utility – or one or more of the entities on which it relies – to generate, transmit, transport, or distribute electricity or natural gas. The Utility has been studying the potential effects of climate change on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

***The Utility is subject to penalties for failure to comply with federal, state, or local statutes and regulations. Changes in the political and regulatory environment could cause federal and state statutes, regulations, rules, and orders to become more stringent and difficult to comply with, and required permits, authorizations, and licenses may be more difficult to obtain, increasing the Utility's expenses or making it more difficult for the Utility to execute its business strategy.***

The Utility must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. In addition to the NRC requirements described above, these include meeting new renewable energy delivery requirements, resource adequacy requirements, federal electric reliability standards, customer billing, customer service, affiliate transactions, vegetation management, operating and maintenance practices, and safety and inspection practices. The Utility is subject to penalties and sanctions for failure to comply with applicable statutes, regulations, rules, tariffs, and orders.

On January 1, 2012, the CPUC's statutory authority to impose penalties increased from up to $20,000 per day, per violation, to up to $50,000 per day, per violation. The CPUC has wide discretion to determine, based on the facts and circumstances, whether a single violation or multiple violations were committed and to determine the length of time a violation existed for purposes of calculating the amount of penalties. The CPUC has delegated authority to the SED to levy citations and impose penalties for violations of certain regulations related to the safety of natural gas facilities and utilities' natural gas operating practices. Like the CPUC, the SED has discretion to determine how to count the number of violations, but the delegated authority requires the SED to assess the maximum statutory fine per violation. (For a discussion of pending investigations and potential enforcement proceedings, see MD&A "Natural Gas Matters" above.) There is a risk that the CPUC could delegate additional enforcement authority to its staff or that legislation could be enacted to require the CPUC to further delegate enforcement authority.

In addition, the federal Pipeline and Hazardous Materials Safety Administration can impose penalties for violation of federal pipeline safety regulations in amounts that range from $100,000 to $200,000 for an individual violation and from $1 million to $2 million for a series of violations.

The Utility must comply with federal electric reliability standards that are set by the North American Electric Reliability Corporation and approved by the FERC. These standards relate to maintenance, training, operations, planning, vegetation management, facility ratings, and other subjects. These standards are designed to maintain the reliability of the nation's bulk power system and to protect the system against potential disruptions from cyber-attacks and physical security breaches. The FERC can impose penalties (up to $1 million per day, per violation) for failure to comply with these mandatory electric reliability standards. As these and other standards and rules evolve, and as the wholesale electricity markets become more complex, the Utility's risk of noncompliance may increase.

In addition, statutes, regulations, rules, tariffs, and orders, or their interpretation and application, may become more stringent and difficult to comply with in the future. If this occurs, the Utility could be exposed to increased costs to comply with the more stringent requirements or new interpretations and to potential liability for customer refunds, penalties, or other amounts. If it is determined that the Utility did not comply with applicable statutes, regulations, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially affected.

The Utility also must comply with the terms of various permits, authorizations, and licenses. These permits, authorizations, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses often have a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, or licenses, or if the Utility cannot recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially affected.

***Market performance or changes in other assumptions could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. Up to approximately 60% of the plan assets and trust assets have generally been invested in equity securities, which are subject to market fluctuation. A decline in the market value may increase the funding requirements for these plans and trusts.

The cost of providing pension and other postretirement benefits is also affected by other factors, including the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements, changes in assumptions as to decommissioning dates, technology and costs of labor, materials and equipment change, and assumed rate of return on plan assets. For example, changes in interest rates affect the liabilities under the plans: as interest rates decrease, the liabilities increase, potentially increasing the funding requirements.

The Utility has recorded an asset retirement obligation related to decommissioning its nuclear facilities based on various estimates and assumptions. Changes in these estimates and assumptions can materially affect the amount of the recorded asset retirement obligation. (See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the increase in the recorded asset retirement obligation to reflect increased estimated decommissioning costs.)

The CPUC has authorized the Utility to recover forecasted costs to fund pension and postretirement plan contributions and nuclear decommissioning through rates. If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans and nuclear decommissioning trusts and is unable to recover such contributions in rates, the contributions would negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Other Utility obligations, such as its workers' compensation obligations, are not separately earmarked for recovery through rates. Therefore, increases in the Utility's workers' compensation liabilities and other unfunded liabilities also can negatively affect net income.

***PG&E Corporation's and the Utility's financial statements reflect various estimates, assumptions, and values and are prepared in accordance with applicable accounting rules, standards, policies, guidance, and interpretations, including those related to regulatory assets and liabilities. Changes to these estimates, assumptions, values, and accounting rules, or changes in the application of these rules, could materially affect PG&E Corporation's and the Utility's financial condition or results of operations.***

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets, and liabilities, and the disclosure of contingencies. (See the discussion under Notes 1 and 2 of the Notes to the Consolidated Financial Statements and "Critical Accounting Policies" above.) If the information on which the estimates and assumptions are based proves to be incorrect or incomplete, if future events do not occur as anticipated, or if there are changes in applicable accounting guidance, policies, or interpretation, management's estimates and assumptions will change as appropriate. A change in management's estimates or assumptions, or the recognition of actual losses that differ from the amount of estimated losses, could have a material impact on PG&E Corporation's and the Utility's financial condition or results of operations.

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. At December 31, 2012, PG&E Corporation and the Utility reported regulatory assets of $8.3 billion and regulatory liabilities of $6.1 billion. (See Note 3 of the Notes to the Consolidated Financial Statements.) Management believes that currently available facts support the continued application of regulatory accounting and that all regulatory assets and liabilities are recoverable or refundable in the current rate environment. Since the San Bruno accident in September 2010, the Utility has recorded cumulative charges of approximately $1.83 billion related to its natural gas operations that are not recoverable through rates. To the extent that rates are not set at a level that allows the Utility to recover the cost of providing service and a reasonable return on its investment in future periods, the Utility may be required to discontinue the application of regulatory accounting for portions of its operations. If that occurs, the related regulatory assets and liabilities would be charged against income in the period in which that determination was made and could have a material impact on PG&E Corporation's and the Utility's future financial condition and results of operations.

***As a holding company, PG&E Corporation depends on cash distributions and reimbursements from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.***

PG&E Corporation is a holding company with no revenue generating operations of its own. PG&E Corporation's ability to pay interest on its outstanding debt, the principal at maturity, and to pay dividends on its common stock, as well as satisfy its other financial obligations, primarily depends on the earnings and cash flows of the Utility and the ability of the Utility to distribute cash to PG&E Corporation (in the form of dividends and share repurchases) and reimburse PG&E Corporation for the Utility's share of applicable expenses. Before it can distribute cash to PG&E Corporation, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors. The Utility's ability to pay common stock dividends is constrained by regulatory requirements, including that the Utility maintain its authorized capital structure with an average 52% equity component. Further, the CPUC could adopt the SED's financial recommendations made in its January 12, 2012 report on the San Bruno accident, including that the Utility "should target retained earnings towards safety improvements before providing dividends, especially if the Utility's ROE exceeds the level set in a GRC." PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. If the Utility is not able to make distributions to PG&E Corporation or to reimburse PG&E Corporation, PG&E Corporation's ability to meet its own obligations could be impaired and its ability to pay dividends could be restricted.

***PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.***

The CPUC imposed certain conditions when it approved the original formation of a holding company for the Utility, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC later issued decisions adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The Utility's financial condition will be affected by the amount of costs the Utility incurs that it is not allowed to recover through rates, the amount of third-party losses it is unable to recover through insurance, and the amount of penalties the Utility incurs in connection with the pending investigations and future citations for self-reported violations. After considering these impacts, the CPUC's interpretation of PG&E Corporation's obligation under the first priority condition could require PG&E Corporation to infuse the Utility with significant capital in the future or could prevent distributions from the Utility to PG&E Corporation, or both, any of which could materially restrict PG&E Corporation's ability to pay principal and interest on its outstanding debt or pay its common stock dividend, meet other obligations, or execute its business strategy. Further, laws or regulations could be enacted or adopted in the future that could impose additional financial or other restrictions or requirements pertaining to transactions between a holding company and its regulated subsidiaries.

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.***

The Utility relies on access to capital and credit markets as significant sources of liquidity to fund capital expenditures, pay principal and interest on its debt, provide collateral to support its natural gas and electricity procurement hedging contracts, and fund other operations requirements that are not satisfied by operating cash flows. See the discussion of the Utility's future financing needs above in "Liquidity and Financial Resources." PG&E Corporation relies on independent access to the capital and credit markets to fund its operations, make capital expenditures, and contribute equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure, if funds received from the Utility (in the form of dividends or share repurchases) are insufficient to meet such needs. Following the San Bruno accident, PG&E Corporation has issued a material amount of equity to fund its equity contributions to the Utility as the Utility has incurred costs and expenses it cannot recover through rates.

PG&E Corporation forecasts that it will continue to issue additional material amounts of equity as the Utility continues to incur costs that it cannot recover through rates, such as costs under its pipeline safety enhancement plan, to improve electricity and natural gas operations, and to pay penalties. PG&E Corporation may also be required to access the capital markets when the Utility is successful in selling long-term debt so that PG&E Corporation can contribute equity to the Utility as needed to maintain the Utility's authorized capital structure.

PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend on many factors, including the amount of penalties imposed on the Utility in connection with the matters described above under "Natural Gas Maters;" changes in their credit ratings; changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular; the overall health of the energy industry; volatility in electricity or natural gas prices; disruptions, uncertainty or volatility in the capital and credit markets; and general economic and market conditions. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets could be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing capital to the Utility, to enable the Utility to fulfill its obligation to serve. If PG&E Corporation is required to contribute equity to the Utility in these circumstances, it would be required to seek these funds from the capital or credit markets. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| **Operating Revenues** | | | |
| Electric | $ 12,019 | $ 11,606 | $ 10,645 |
| Natural gas | 3,021 | 3,350 | 3,196 |
| **Total operating revenues** | **15,040** | **14,956** | **13,841** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,162 | 4,016 | 3,898 |
| Cost of natural gas | 861 | 1,317 | 1,291 |
| Operating and maintenance | 6,052 | 5,466 | 4,439 |
| Depreciation, amortization, and decommissioning | 2,272 | 2,215 | 1,905 |
| **Total operating expenses** | **13,347** | **13,014** | **11,533** |
| **Operating Income** | 1,693 | 1,942 | 2,308 |
| Interest income | 7 | 7 | 9 |
| Interest expense | (703) | (700) | (684) |
| Other income, net | 70 | 49 | 27 |
| **Income Before Income Taxes** | **1,067** | **1,298** | **1,660** |
| Income tax provision | 237 | 440 | 547 |
| **Net Income** | **830** | **858** | **1,113** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 816** | **$ 844** | **$ 1,099** |
| **Weighted Average Common Shares Outstanding, Basic** | **424** | **401** | **382** |
| **Weighted Average Common Shares Outstanding, Diluted** | **425** | **402** | **392** |
| **Net Earnings Per Common Share, Basic** | **$ 1.92** | **$ 2.10** | **$ 2.86** |
| **Net Earnings Per Common Share, Diluted** | **$ 1.92** | **$ 2.10** | **$ 2.82** |
| **Dividends Declared Per Common Share** | **$ 1.82** | **$ 1.82** | **$ 1.82** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2012** | **2011** | **2010** |
| **Net Income** | **$ 830** | **$ 858** | **$ 1,113** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans | | | |
| Unrecognized prior service credit (cost) (net of income tax of $14, $24, and $20 in 2012, 2011, and 2010, respectively) | 17 | 36 | (29) |
| Unrecognized net gain (loss) (net of income tax of $20, $452, and $73 in 2012 , 2011, and 2010, respectively) | 31 | (655) | (110) |
| Unrecognized net transition obligation (net of income tax of $8 in 2012, and $11 in 2011 and 2010, respectively) | 16 | 15 | 15 |
| Transfer to regulatory account (net of income tax of $30, $408, and $57 in 2012, 2011, and 2010, respectively) | 44 | 593 | 82 |
| Other (net of income tax of $3 in 2012) | 4 | - | - |
| **Total other comprehensive income (loss)** | **112** | **(11)** | **(42)** |
| **Comprehensive Income** | **942** | **847** | **1,071** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 928** | **$ 833** | **$ 1,057** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, 2012 | Balance at December 31, 2011 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 401 | $ 513 |
| Restricted cash ($0 and $51 related to energy recovery bonds at December 31, 2012 and 2011, respectively) | 330 | 380 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $87 and $81 at December 31, 2012 and 2011, respectively) | 937 | 992 |
| Accrued unbilled revenue | 761 | 763 |
| Regulatory balancing accounts | 936 | 1,082 |
| Other | 365 | 839 |
| Regulatory assets ($0 and $336 related to energy recovery bonds at December 31, 2012 and 2011, respectively) | 564 | 1,090 |
| Inventories | | |
| Gas stored underground and fuel oil | 135 | 159 |
| Materials and supplies | 309 | 261 |
| Income taxes receivable | 211 | 183 |
| Other | 172 | 218 |
| **Total current assets** | **5,121** | **6,480** |
| **Property, Plant, and Equipment** | | |
| Electric | 39,701 | 35,851 |
| Gas | 12,571 | 11,931 |
| Construction work in progress | 1,894 | 1,770 |
| Other | 1 | 15 |
| **Total property, plant, and equipment** | **54,167** | **49,567** |
| Accumulated depreciation | (16,644) | (15,912) |
| **Net property, plant, and equipment** | **37,523** | **33,655** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 6,809 | 6,506 |
| Nuclear decommissioning trusts | 2,161 | 2,041 |
| Income taxes receivable | 176 | 386 |
| Other | 659 | 682 |
| **Total other noncurrent assets** | **9,805** | **9,615** |
| **TOTAL ASSETS** | **$ 52,449** | **$ 49,750** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, 2012 | Balance at December 31, 2011 |
|---|---|---|
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 492 | $ 1,647 |
| Long-term debt, classified as current | 400 | 50 |
| Energy recovery bonds, classified as current | - | 423 |
| Accounts payable | | |
| Trade creditors | 1,241 | 1,177 |
| Disputed claims and customer refunds | 157 | 673 |
| Regulatory balancing accounts | 634 | 374 |
| Other | 444 | 420 |
| Interest payable | 870 | 843 |
| Income taxes payable | 6 | 110 |
| Deferred income taxes | - | 196 |
| Other | 2,012 | 1,836 |
| **Total current liabilities** | **6,256** | **7,749** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 12,517 | 11,766 |
| Regulatory liabilities | 5,088 | 4,733 |
| Pension and other postretirement benefits | 3,575 | 3,396 |
| Asset retirement obligations | 2,919 | 1,609 |
| Deferred income taxes | 6,748 | 6,008 |
| Other | 2,020 | 2,136 |
| **Total noncurrent liabilities** | **32,867** | **29,648** |
| **Commitments and Contingencies (Note 15)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Preferred stock | - | - |
| Common stock, no par value, authorized 800,000,000 shares, 430,718,293 shares outstanding at December 31, 2012 and 412,257,082 shares outstanding at December 31, 2011 | 8,428 | 7,602 |
| Reinvested earnings | 4,747 | 4,712 |
| Accumulated other comprehensive loss | (101) | (213) |
| **Total shareholders' equity** | **13,074** | **12,101** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **13,326** | **12,353** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 52,449** | **$ 49,750** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 830 | $ 858 | $ 1,113 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,272 | 2,215 | 1,905 |
| Allowance for equity funds used during construction | (107) | (87) | (110) |
| Deferred income taxes and tax credits, net | 648 | 544 | 756 |
| Disallowed capital expenditures | 353 | - | 36 |
| Other | 290 | 326 | 257 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (40) | (288) | (44) |
| Inventories | (24) | (63) | (43) |
| Accounts payable | (4) | 65 | 48 |
| Income taxes receivable/payable | (132) | (103) | (78) |
| Other current assets and liabilities | 262 | 23 | 111 |
| Regulatory assets, liabilities, and balancing accounts, net | 291 | (100) | (394) |
| Other noncurrent assets and liabilities | 243 | 349 | (351) |
| **Net cash provided by operating activities** | **4,882** | **3,739** | **3,206** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (4,624) | (4,038) | (3,802) |
| Decrease in restricted cash | 50 | 200 | 66 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,133 | 1,928 | 1,405 |
| Purchases of nuclear decommissioning trust investments | (1,189) | (1,963) | (1,456) |
| Other | 104 | (113) | (70) |
| **Net cash used in investing activities** | **(4,526)** | **(3,986)** | **(3,857)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings under revolving credit facilities | 120 | 358 | 490 |
| Repayments under revolving credit facilities | - | (358) | (490) |
| Net issuances (repayments) of commercial paper, net of discount of $3 in 2012, $4 in 2011, and $3 in 2010 | (1,021) | 782 | 267 |
| Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010 | - | 250 | 249 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2012, $8 in 2011, and $23 in 2010 | 1,137 | 792 | 1,327 |
| Short-term debt matured | (250) | (250) | (500) |
| Long-term debt matured or repurchased | (50) | (700) | (95) |
| Energy recovery bonds matured | (423) | (404) | (386) |
| Common stock issued | 751 | 662 | 303 |
| Common stock dividends paid | (746) | (704) | (662) |
| Other | 14 | 41 | (88) |
| **Net cash provided by (used in) financing activities** | **(468)** | **469** | **415** |
| **Net change in cash and cash equivalents** | **(112)** | **222** | **(236)** |
| **Cash and cash equivalents at January 1** | **513** | **291** | **527** |
| **Cash and cash equivalents at December 31** | **$ 401** | **$ 513** | **$ 291** |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (594) | $ (647) | $ (627) |
| Income taxes, net | 114 | (42) | (135) |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Common stock dividends declared but not yet paid | $ 196 | $ 188 | $ 183 |
| Capital expenditures financed through accounts payable | 362 | 308 | 364 |
| Noncash common stock issuances | 22 | 24 | 265 |
| Terminated capital leases | 136 | - | - |



See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | **Common Stock Shares** | **Common Stock Amount** | **Reinvested Earnings** | **Accumulated Other Comprehensive Income (Loss)** | **Total Shareholders' Equity** | **Noncontrolling Interest - Preferred Stock of Subsidiary** | **Total Equity** |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2009** | **371,272,457** | **$ 6,280** | **$ 4,213** | **$ (160)** | **$ 10,333** | **$ 252** | **$ 10,585** |
| Net income | - | - | 1,113 | - | 1,113 | - | 1,113 |
| Other comprehensive loss | - | - | - | (42) | (42) | - | (42) |
| Common stock issued, net | 23,954,748 | 568 | - | - | 568 | - | 568 |
| Stock-based compensation amortization | - | 34 | - | - | 34 | - | 34 |
| Common stock dividends declared | - | - | (706) | - | (706) | - | (706) |
| Tax expense from employee stock plans | - | (4) | - | - | (4) | - | (4) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2010** | **395,227,205** | **6,878** | **4,606** | **(202)** | **11,282** | **252** | **11,534** |
| Net income | - | - | 858 | - | 858 | - | 858 |
| Other comprehensive loss | - | - | - | (11) | (11) | - | (11) |
| Common stock issued, net | 17,029,877 | 686 | - | - | 686 | - | 686 |
| Stock-based compensation amortization | - | 37 | - | - | 37 | - | 37 |
| Common stock dividends declared | - | - | (738) | - | (738) | - | (738) |
| Tax benefit from employee stock plans | - | 1 | - | - | 1 | - | 1 |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2011** | **412,257,082** | **7,602** | **4,712** | **(213)** | **12,101** | **252** | **12,353** |
| Net income | - | - | 830 | - | 830 | - | 830 |
| Other comprehensive income | - | - | - | 112 | 112 | - | 112 |
| Common stock issued, net | 18,461,211 | 773 | - | - | 773 | - | 773 |
| Stock-based compensation amortization | - | 52 | - | - | 52 | - | 52 |
| Common stock dividends declared | - | - | (781) | - | (781) | - | (781) |
| Tax benefit from employee stock plans | - | 1 | - | - | 1 | - | 1 |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2012** | **430,718,293** | **$ 8,428** | **$ 4,747** | **$ (101)** | **$ 13,074** | **$ 252** | **$ 13,326** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| **Operating Revenues** | | | |
| Electric | $ 12,014 | $ 11,601 | $ 10,644 |
| Natural gas | 3,021 | 3,350 | 3,196 |
| **Total operating revenues** | **15,035** | **14,951** | **13,840** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,162 | 4,016 | 3,898 |
| Cost of natural gas | 861 | 1,317 | 1,291 |
| Operating and maintenance | 6,045 | 5,459 | 4,432 |
| Depreciation, amortization, and decommissioning | 2,272 | 2,215 | 1,905 |
| **Total operating expenses** | **13,340** | **13,007** | **11,526** |
| **Operating Income** | 1,695 | 1,944 | 2,314 |
| Interest income | 6 | 5 | 9 |
| Interest expense | (680) | (677) | (650) |
| Other income, net | 88 | 53 | 22 |
| **Income Before Income Taxes** | **1,109** | **1,325** | **1,695** |
| Income tax provision | 298 | 480 | 574 |
| **Net Income** | **811** | **845** | **1,121** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 797** | **$ 831** | **$ 1,107** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2012** | **2011** | **2010** |
| **Net Income** | **$ 811** | **$ 845** | **$ 1,121** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans | | | |
| Unrecognized prior service credit (cost) (net of income tax of $13, $24, and $21 in 2012, 2011, and 2010, respectively) | 16 | 36 | (30) |
| Unrecognized net gain (loss) (net of income tax of $22, $447, and $74 in 2012, 2011, and 2010, respectively) | 33 | (651) | (108) |
| Unrecognized net transition obligation (net of income tax of $8 in 2012, and $11 in 2011 and 2010, respectively) | 16 | 15 | 15 |
| Transfer to regulatory account (net of income tax of $30, $408, and $57 in 2012, 2011, and 2010, respectively) | 44 | 593 | 82 |
| **Total other comprehensive income (loss)** | **109** | **(7)** | **(41)** |
| **Comprehensive Income** | **$ 920** | **$ 838** | **$ 1,080** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, 2012 | Balance at December 31, 2011 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 194 | $ 304 |
| Restricted cash ($0 and $51 related to energy recovery bonds at December 31, 2012 and 2011, respectively) | 330 | 380 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $87 and $81 at December 31, 2012 and 2011, respectively) | 937 | 992 |
| Accrued unbilled revenue | 761 | 763 |
| Regulatory balancing accounts | 936 | 1,082 |
| Other | 366 | 840 |
| Regulatory assets ($0 and $336 related to energy recovery bonds at December 31, 2012 and 2011, respectively) | 564 | 1,090 |
| Inventories | | |
| Gas stored underground and fuel oil | 135 | 159 |
| Materials and supplies | 309 | 261 |
| Income taxes receivable | 186 | 242 |
| Other | 160 | 213 |
| **Total current assets** | **4,878** | **6,326** |
| **Property, Plant, and Equipment** | | |
| Electric | 39,701 | 35,851 |
| Gas | 12,571 | 11,931 |
| Construction work in progress | 1,894 | 1,770 |
| **Total property, plant, and equipment** | **54,166** | **49,552** |
| Accumulated depreciation | (16,643) | (15,898) |
| **Net property, plant, and equipment** | **37,523** | **33,654** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 6,809 | 6,506 |
| Nuclear decommissioning trusts | 2,161 | 2,041 |
| Income taxes receivable | 171 | 384 |
| Other | 381 | 331 |
| **Total other noncurrent assets** | **9,522** | **9,262** |
| **TOTAL ASSETS** | **$ 51,923** | **$ 49,242** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, 2012 | Balance at December 31, 2011 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 372 | $ 1,647 |
| Long-term debt, classified as current | 400 | 50 |
| Energy recovery bonds, classified as current | - | 423 |
| Accounts payable | | |
| Trade creditors | 1,241 | 1,177 |
| Disputed claims and customer refunds | 157 | 673 |
| Regulatory balancing accounts | 634 | 374 |
| Other | 419 | 417 |
| Interest payable | 865 | 838 |
| Income taxes payable | 12 | 118 |
| Deferred income taxes | - | 199 |
| Other | 1,794 | 1,628 |
| **Total current liabilities** | **5,894** | **7,544** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 12,167 | 11,417 |
| Regulatory liabilities | 5,088 | 4,733 |
| Pension and other postretirement benefits | 3,497 | 3,325 |
| Asset retirement obligations | 2,919 | 1,609 |
| Deferred income taxes | 6,939 | 6,160 |
| Other | 1,959 | 2,070 |
| **Total noncurrent liabilities** | **32,569** | **29,314** |
| **Commitments and Contingencies (Note 15)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at December 31, 2012 and 2011 | 1,322 | 1,322 |
| Additional paid-in capital | 4,682 | 3,796 |
| Reinvested earnings | 7,291 | 7,210 |
| Accumulated other comprehensive loss | (93) | (202) |
| **Total shareholders' equity** | **13,460** | **12,384** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 51,923** | **$ 49,242** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 811 | $ 845 | $ 1,121 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,272 | 2,215 | 1,905 |
| Allowance for equity funds used during construction | (107) | (87) | (110) |
| Deferred income taxes and tax credits, net | 684 | 582 | 762 |
| Disallowed capital expenditures | 353 | - | 36 |
| Other | 236 | 289 | 221 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (40) | (227) | (105) |
| Inventories | (24) | (63) | (43) |
| Accounts payable | (26) | 51 | 109 |
| Income taxes receivable/payable | (50) | (192) | (58) |
| Other current assets and liabilities | 272 | 36 | 123 |
| Regulatory assets, liabilities, and balancing accounts, net | 291 | (100) | (394) |
| Other noncurrent assets and liabilities | 256 | 414 | (331) |
| **Net cash provided by operating activities** | **4,928** | **3,763** | **3,236** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (4,624) | (4,038) | (3,802) |
| Decrease in restricted cash | 50 | 200 | 66 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,133 | 1,928 | 1,405 |
| Purchases of nuclear decommissioning trust investments | (1,189) | (1,963) | (1,456) |
| Other | 16 | 14 | 19 |
| **Net cash used in investing activities** | **(4,614)** | **(3,859)** | **(3,768)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings under revolving credit facilities | - | 208 | 400 |
| Repayments under revolving credit facilities | - | (208) | (400) |
| Net issuances (repayments) of commercial paper, net of discount of $3 in 2012, $4 in 2011, and $3 in 2010 | (1,021) | 782 | 267 |
| Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010 | - | 250 | 249 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2012, $8 in 2011, and $23 in 2010 | 1,137 | 792 | 1,327 |
| Short-term debt matured | (250) | (250) | (500) |
| Long-term debt matured or repurchased | (50) | (700) | (95) |
| Energy recovery bonds matured | (423) | (404) | (386) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution | 885 | 555 | 190 |
| Other | 28 | 54 | (73) |
| **Net cash provided by (used in) financing activities** | **(424)** | **349** | **249** |
| **Net change in cash and cash equivalents** | **(110)** | **253** | **(283)** |
| **Cash and cash equivalents at January 1** | **304** | **51** | **334** |
| **Cash and cash equivalents at December 31** | **$ 194** | **$ 304** | **$ 51** |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (574) | $ (627) | $ (595) |
| Income taxes, net | 174 | (50) | (171) |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Capital expenditures financed through accounts payable | $ 362 | $ 308 | $ 364 |
| Terminated capital leases | 136 | - | - |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**
**(in millions)**

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2009** | **$ 258** | **$ 1,322** | **$ 3,055** | **$ 6,704** | **$ (154)** | **$ 11,185** |
| Net income | - | - | - | 1,121 | - | 1,121 |
| Other comprehensive loss | - | - | - | - | (41) | (41) |
| Equity contribution | - | - | 190 | - | - | 190 |
| Tax expense from employee stock plans | - | - | (4) | - | - | (4) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2010** | **258** | **1,322** | **3,241** | **7,095** | **(195)** | **11,721** |
| Net income | - | - | - | 845 | - | 845 |
| Other comprehensive loss | - | - | - | - | (7) | (7) |
| Equity contribution | - | - | 555 | - | - | 555 |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2011** | **258** | **1,322** | **3,796** | **7,210** | **(202)** | **12,384** |
| Net income | - | - | - | 811 | - | 811 |
| Other comprehensive income | - | - | - | - | 109 | 109 |
| Equity contribution | - | - | 885 | - | - | 885 |
| Tax benefit from employee stock plans | - | - | 1 | - | - | 1 |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2012** | **$ 258** | **$ 1,322** | **$ 4,682** | **$ 7,291** | **$ (93)** | **$ 13,460** |

See accompanying Notes to the Consolidated Financial Statements.

**NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION**

PG&E Corporation is a holding company that conducts its business through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility's accounts for electric and gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the FERC.

This is a combined annual report of PG&E Corporation and the Utility. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the Consolidated Financial Statements. PG&E Corporation and the Utility operate in one segment.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the Securities and Exchange Commission ("SEC"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions, that are difficult to predict. Some of the more critical estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations ("ARO"), and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

**NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

**Restricted Cash**

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 13 below.)

**Allowance for Doubtful Accounts Receivable**

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

**Inventories**

Inventories are carried at weighted-average cost. Inventories include natural gas stored underground and materials and supplies. Natural gas stored underground represents purchases that are recorded to inventory and then expensed at weighted average cost when withdrawn and distributed to customers or used in electric generation. Materials and supplies are recorded to inventory when purchased and then expensed or capitalized to plant, as appropriate, when consumed or installed.

**Property, Plant, and Equipment**

Property, plant, and equipment are reported at their original cost. These original costs include labor and materials, construction overhead, and allowance for funds used during construction ("AFUDC"). The Utility's estimated useful lives and balances of its property, plant, and equipment were as follows:

| | Estimated Useful | Balance at December 31, | |
|---|---|---|---|
| **(in millions, except estimated useful lives)** | **Lives (years)** | **2012** | **2011** |
| Electricity generating facilities [1] | 10 to 100 | $ 8,253 | $ 6,488 |
| Electricity distribution facilities | 10 to 55 | 23,767 | 22,395 |
| Electricity transmission | 10 to 70 | 7,681 | 6,968 |
| Natural gas distribution facilities | 20 to 53 | 8,257 | 7,832 |
| Natural gas transportation and storage | 5 to 48 | 4,314 | 4,099 |
| Construction work in progress | | 1,894 | 1,770 |
| **Total property, plant, and equipment** | | **54,166** | **49,552** |
| Accumulated depreciation | | (16,643) | (15,898) |
| **Net property, plant, and equipment** | | **$ 37,523** | **$ 33,654** |

[1] Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 15 below.)

**Depreciation**

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.63% in 2012, 3.67% in 2011, and 3.38% in 2010.

The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC is a method used to compensate the Utility for the estimated cost of debt (i.e., interest) and equity funds used to finance regulated plant additions and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC of $49 million and $107 million during 2012, $40 million and $87 million during 2011, and $50 million and $110 million during 2010, related to debt and equity, respectively.

**Regulation and Regulated Operations**

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

The Utility's ability to recover the revenue requirements that have been authorized by the CPUC in a general rate case ("GRC") and a gas transmission and storage rate case ("GT&S") does not depend on the volume of the Utility's sales of electricity and natural gas services. The Utility's recovery of a significant portion of its authorized revenue requirements through rates is independent, or "decoupled," from the volume of electricity and natural gas sales.

The Utility records differences between actual customer billings and the Utility's authorized revenue requirement, as well as differences between incurred costs and customer billings or authorized revenue meant to recover those costs. To the extent these differences are probable of recovery or refund, the Utility records a regulatory balancing account asset or liability, respectively and the differences do not have an impact on net income. For further discussion, see "Revenue Recognition" below.

To the extent that portions of the Utility's operations cease to be subject to cost-of-service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

**Intangible Assets**

Intangible assets primarily consist of hydroelectric facility licenses with terms ranging from 19 to 53 years. The gross carrying amount of intangible assets was $110 million at December 31, 2012 and $112 million at December 31, 2011. The accumulated amortization was $49 million at December 31, 2012 and $47 million at December 31, 2011.

The Utility's amortization expense related to intangible assets was $2 million in 2012, $3 million in 2011, and $4 million in 2010. The estimated annual amortization expense for 2013 through 2017 based on the December 31, 2012 intangible assets balance is $3 million. Intangible assets are recorded to other noncurrent assets – other in the Consolidated Balance Sheets.

**Asset Retirement Obligations**

PG&E Corporation and the Utility record an ARO at discounted fair value in the period in which the obligation is incurred if the discounted fair value can be reasonably estimated. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the ARO is accreted to its present value. PG&E Corporation and the Utility also record an ARO if a legal obligation to perform an asset removal exists and can be reasonably estimated, but performance is conditional upon a future event. The Utility recognizes timing differences between the recognition of costs and the costs recovered through the ratemaking process as regulatory assets or liabilities. (See Note 3 below.) The Utility has an ARO primarily for its nuclear generation facilities, certain fossil fuel-fired generation facilities, and gas transmission system assets.

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceedings ("NDCTP") conducted by the CPUC. In December 2012, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by $1.4 billion due to higher spent nuclear fuel disposal costs and an increase in the scope of work. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear generation facilities. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. A significant portion of the increase in decommissioning cost estimates is due to the need to develop on-site storage for spent nuclear fuel because the federal government has failed to meet its obligation to develop a permanent repository for the disposal of nuclear waste from nuclear facilities in the United States. The Utility expects that it will recover its future on-site storage costs from the federal government. The Utility already has recovered $266 million for spent nuclear fuel costs incurred through 2010. (See "Spent Nuclear Fuel Storage Proceedings" in Note 15 below). Recovered amounts will be refunded to customers through rates. In its 2012 NDCTP application, the Utility requested that the CPUC issue a final decision by the end of 2013.

The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear generation facilities was approximately $3.5 billion at December 31, 2012 and $2.3 billion at December 31, 2011, as filed in the 2012 and 2009 NDCTPs, respectively. In future dollars, the estimated nuclear decommissioning cost is approximately $6.1 billion and $4.4 billion, respectively. These estimates are based on the 2012 and 2009 decommissioning cost studies, respectively, and are prepared in accordance with CPUC requirements. The estimated nuclear decommissioning cost in future dollars is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $2.5 billion at December 31, 2012 and $1.2 billion at December 31, 2011.

A reconciliation of the changes in the ARO liability is as follows:

| (in millions) | | |
|---|---|---|
| ARO liability at December 31, 2010 | $ | 1,586 |
| Revision in estimated cash flows | | 10 |
| Accretion | | 100 |
| Liabilities settled | | (87) |
| ARO liability at December 31, 2011 | | **1,609** |
| Revision in estimated cash flows | | 1,301 |
| Accretion | | 101 |
| Liabilities settled | | (92) |
| **ARO liability at December 31, 2012** | **$** | **2,919** |

The Utility has identified the following AROs for which a reasonable estimate of fair value could not be made. As a result, the Utility has not recorded a liability related to these AROs:

- *Restoration of land to its pre-use condition under the terms of certain land rights agreements.* Land rights will be maintained for the foreseeable future, and therefore, the Utility cannot reasonably estimate the settlement date(s) or range of settlement dates for the obligations associated with these assets;

- *Removal and proper disposal of lead-based paint contained in some Utility facilities.* The Utility does not have information available that specifies which facilities contain lead-based paint and, therefore, cannot reasonably estimate the settlement date(s) associated with the obligations; and

- *Removal of certain communications equipment from leased property, and retirement activities associated with substation and certain hydroelectric facilities.* The Utility will maintain and continue to operate its hydroelectric facilities until the operation of a facility becomes uneconomical. The operation of the majority of the Utility's hydroelectric facilities is currently, and for the foreseeable future, expected to be economically beneficial. Therefore, the settlement date(s) cannot be reasonably estimated at this time.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge to net income when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. During 2012, the Utility recorded a $353 million charge to net income for capital expenditures incurred in connection with its pipeline safety enhancement plan that were either specifically disallowed or that are forecasted to exceed the CPUC's authorized levels. (See "CPUC Gas Safety Rulemaking Proceeding" in Note 15 below). No material disallowance losses were recorded in 2011 and $36 million in disallowance losses were recorded in 2010.

**Gains and Losses on Debt Extinguishments**

Gains and losses on debt extinguishments associated with regulated operations are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. PG&E Corporation and the Utility recorded unamortized loss on debt extinguishments, net of gain, of $163 million and $186 million at December 31, 2012 and 2011, respectively. The amortization expense related to this loss was $23 million in 2012, $18 million in 2011, and $23 million in 2010. Deferred gains and losses on debt extinguishments are recorded to current assets – regulatory assets and other noncurrent assets – regulatory assets in the Consolidated Balance Sheets.

Gains and losses on debt extinguishments associated with unregulated operations are fully recognized at the time such debt is reacquired and are reported as a component of interest expense.

**Revenue Recognition**

The Utility recognizes revenues as electricity and natural gas services are delivered, and includes amounts for services rendered but not yet billed at the end of the period.

The CPUC authorizes most of the Utility's revenue requirements in its GRC and its GT&S, which generally occur every three years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues once they have been authorized for rate recovery, amounts are objectively determinable and probable of recovery, and amounts will be collected within 24 months. Generally, the revenue recognition criteria are met ratably over the year. (See Note 3 below.)

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. Generally, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility's revenue requirements in annual transmission owner rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled.

The Utility's revenues and net income also are affected by incentive ratemaking mechanisms that adjust rates depending on the extent to which the Utility meets certain performance criteria.

**Income Taxes**

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period actual tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as depreciation, and are reported within the PG&E Corporation and Utility's balance sheets. (See Note 9 below.)

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period.

PG&E Corporation files a consolidated U.S. federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. In addition, PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

**Nuclear Decommissioning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold is determined by specific identification.

**Accounting for Derivatives**

Derivative instruments are recorded in PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value, unless they qualify for the normal purchase and sales exception. Changes in the fair value of derivative instruments are recorded in earnings or, to the extent that they are probable of future recovery through regulated rates, are deferred and recorded in regulatory accounts.

The normal purchase and sales exception to derivative accounting requires, among other things, physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business. Transactions which qualify for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets at fair value, but are accounted for under the accrual method of accounting. Therefore, expenses are recognized as incurred.

PG&E Corporation and the Utility offset cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement where the right of offset and the intention to offset exist. (See Note 10 below.)

**Fair Value Measurements**

PG&E Corporation and the Utility determine the fair value of certain assets and liabilities based on assumptions that market participants would use in pricing the assets or liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or the "exit price." PG&E Corporation and the Utility utilize a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value and give precedence to observable inputs in determining fair value. An instrument's level within the hierarchy is based on the lowest level of any significant input to the fair value measurement. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). (See Note 11 below.)

**Variable Interest Entities**

PG&E Corporation and the Utility are required to consolidate the financial results of any entities that they control. In most cases, control can be determined based on majority ownership or voting interests. However, there are certain entities known as variable interest entities ("VIEs") for which control is difficult to discern based on ownership or voting interests alone. A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest in a VIE if it has the obligation to absorb expected losses or the right to receive expected gains that could potentially be significant to the VIE and if it has any decision-making rights associated with the activities that are most significant to the VIE's economic performance, including the power to design the VIE. An enterprise that has a controlling financial interest in a VIE is known as the VIE's primary beneficiary and is required to consolidate the VIE.

In determining whether consolidation of a particular entity is required, PG&E Corporation and the Utility first evaluate whether the entity is a VIE. If the entity is a VIE, PG&E Corporation and the Utility use a qualitative approach to determine if either is the primary beneficiary of the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility subject to the terms of a power purchase agreement. In determining whether the Utility is the primary beneficiary of any of these VIEs, it assesses whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement. This assessment includes an evaluation of how the risks and rewards associated with the power plant's activities are absorbed by variable interest holders, as well as an analysis of the variability in the VIE's gross margin and the impact of the power purchase agreement on the gross margin. Under each of these power purchase agreements, the Utility is obligated to purchase electricity or capacity, or both, from the VIE. The Utility does not provide any other support to these VIEs, and the Utility's financial exposure is limited to the amount it pays for delivered electricity and capacity. (See Note 15 below.) The Utility does not have any decision-making rights associated with the design of any VIEs, nor does the Utility have the power to direct the activities that are most significant to the economic performance of any VIEs such as dispatch rights, operating and maintenance activities, or re-marketing activities of the power plant after the termination of any VIE's power purchase agreement with the Utility. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2012, it did not consolidate any of them.

The Utility continued to consolidate the financial results of PG&E Energy Recovery Funding LLC ("PERF"), a VIE, at December 31, 2012, since the Utility is the primary beneficiary of PERF. PERF was formed in 2005 as a wholly owned subsidiary of the Utility to issue energy recovery bonds ("ERBs") in connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11 ("Chapter 11 Settlement Agreement"). The Utility has a controlling financial interest in PERF since the Utility is exposed to PERF's losses and returns through the Utility's 100% equity investment in PERF and the Utility was involved in the design of PERF, which was an activity that was significant to PERF's economic performance. PERF is expected to be dissolved in 2013. (See Note 5 below.) While PERF is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets (including the recovery property) of PERF are not available to creditors of the Utility of PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

At December 31, 2012, PG&E Corporation affiliates had entered into four tax equity agreements to fund residential and commercial retail solar energy installations with two privately held companies that are considered VIEs. Under these agreements, PG&E Corporation has agreed to provide lease payments and investment contributions of up to $396 million to these companies in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. The majority of these amounts are recorded in other noncurrent assets – other in PG&E Corporation's Consolidated Balance Sheets. At December 31, 2012, PG&E Corporation had made total payments of $361 million under these agreements and received $228 million in benefits and customer payments. In determining whether PG&E Corporation is the primary beneficiary of any of these VIEs, PG&E Corporation assesses which of the variable interest holders has control over these companies' significant economic activities, such as the design of the companies, vendor selection, construction, customer selection, and re-marketing activities after the termination of customer leases. PG&E Corporation determined that these companies control these activities, while its financial exposure from these agreements is generally limited to its lease payments and investment contributions to these companies. Since PG&E Corporation was not the primary beneficiary of any of these VIEs at December 31, 2012, it did not consolidate any of them.

## NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

### Regulatory Assets

#### *Current Regulatory Assets*

At December 31, 2012 and 2011, the Utility had current regulatory assets of $564 million and $1,090 million, respectively. At December 31, 2012, current regulatory assets consisted primarily of $230 million of the current portion of the price risk management regulatory asset, $62 million of the current portion of the Utility's retained generation regulatory assets, and $54 million of the current portion of the electromechanical meters regulatory asset, each of which is expected to be recovered over the next year. (See "Long-Term Regulatory Assets" below.)

#### *Long-Term Regulatory Assets*

Long-term regulatory assets are composed of the following:

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2012** | **2011** |
| Pension benefits | $ 3,275 | $ 2,899 |
| Deferred income taxes | 1,627 | 1,444 |
| Utility retained generation | 552 | 613 |
| Environmental compliance costs | 604 | 520 |
| Price risk management | 210 | 339 |
| Electromechanical meters | 194 | 247 |
| Unamortized loss, net of gain, on reacquired debt | 141 | 163 |
| Other | 206 | 281 |
| **Total long-term regulatory assets** | **$ 6,809** | **$ 6,506** |

The regulatory asset for pension benefits represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP and also includes amounts that otherwise would be recorded to accumulated other comprehensive loss in the Consolidated Balance Sheets. (See Note 12 below.)

The regulatory asset for deferred income taxes represents deferred income tax benefits previously passed through to customers. The CPUC requires the Utility to pass through certain tax benefits to customers by reducing rates, thereby ignoring the effect of deferred taxes. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover the regulatory asset over the average plant depreciation lives of one to 45 years.

In connection with the Chapter 11 Settlement Agreement, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized. The weighted average remaining life of the assets is 12 years.

The regulatory asset for environmental compliance costs represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. The Utility expects to recover these costs over the next 32 years, as the environmental compliance work is performed. (See Note 15 below.)

The regulatory asset for price risk management represents the unrealized losses related to price risk management derivative instruments expected to be recovered as they are realized over the next 10 years as part of the Utility's energy procurement costs. (See Note 10 below.)

The regulatory asset for electromechanical meters represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices. The Utility expects to recover the regulatory asset over the next four years.

The regulatory asset for unamortized loss, net of gain, on reacquired debt represents the expected future recovery of costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the next 14 years, which is the remaining amortization period of the reacquired debt.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, regulatory assets for electromechanical meters, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

**Regulatory Liabilities**

***Current Regulatory Liabilities***

At December 31, 2012 and 2011, the Utility had current regulatory liabilities of $337 million and $161 million, respectively, consisting of amounts that it expects to refund to customers over the next 12 months. At December 31, 2012 current regulatory liabilities primarily included $158 million of ERB over collections, $84 million of proceeds from a greenhouse gas ("GHG") emission auction to comply with California Air Resources Board requirements, and electricity supplier settlement agreements of $50 million (See Note 13 below). Current regulatory liabilities are included within current liabilities – other in the Consolidated Balance Sheets.

***Long-Term Regulatory Liabilities***

Long-term regulatory liabilities are composed of the following:

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2012** | **2011** |
| Cost of removal obligations | $ 3,625 | $ 3,460 |
| Recoveries in excess of AROs | 620 | 611 |
| Public purpose programs | 590 | 499 |
| Other | 253 | 163 |
| **Total long-term regulatory liabilities** | **$ 5,088** | **$ 4,733** |

The regulatory liability for cost of removal obligations represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.

The regulatory liability for recoveries in excess of AROs represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the Utility's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments. (See Note 11 below.)

The regulatory liability for public purpose programs represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances and other energy-using products, the California Solar Initiative program to promote the use of solar energy in homes and commercial, industrial, and agricultural properties, and the Self-Generation Incentive program to promote distributed generation technologies installed on the customer's side of the utility meter.

**Regulatory Balancing Accounts**

The Utility's current regulatory balancing accounts represent the amounts expected to be collected from or refunded to customers through authorized rate adjustments over the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund over the next 12 months are included in other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets.

***Current Regulatory Balancing Accounts, Net***

| | Receivable (Payable) Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2012** | **2011** |
| Distribution revenue adjustment mechanism | $ 219 | $ 223 |
| Utility generation | 117 | 241 |
| Hazardous substance | 56 | 57 |
| Public purpose programs | (83) | 97 |
| Gas fixed cost | 44 | 16 |
| Energy recovery bonds | (43) | (105) |
| Energy procurement | 77 | (48) |
| Department of Energy Settlement | (250) | - |
| Other | 165 | 227 |
| **Total regulatory balancing accounts, net** | **$ 302** | **$ 708** |

The distribution revenue adjustment mechanism balancing account is used to record and recover the authorized electric distribution revenue requirements and certain other electric distribution-related authorized costs. The utility generation balancing account is used to record and recover the authorized revenue requirements associated with Utility-owned electric generation, including capital costs and related non-fuel operating and maintenance expenses. The recovery of these revenue requirements is decoupled from the volume of sales; therefore, the Utility recognizes revenue evenly over the year, even though the level of cash collected from customers fluctuates depending on the volume of electricity sales. During the colder months of winter, there is generally an under-collection in these balancing accounts due to a lower volume of electricity sales and lower rates. During the warmer months of summer, there is generally an over-collection due to a higher volume of electricity sales and higher rates.

The hazardous substance balancing accounts are used to record and recover hazardous substance remediation costs that are eligible for recovery through a CPUC-approved ratemaking mechanism. (See Note 15 below.)

The public purpose programs balancing accounts are primarily used to record and recover the authorized revenue requirements associated with administering public purpose programs, as well as incentive awards earned by the Utility for achieving regulatory targets in the customer energy efficiency programs. The public purpose programs primarily consist of energy efficiency programs, low-income energy efficiency programs, demand response programs, research, development, and demonstration programs, and renewable energy programs.

The gas fixed-cost balancing account is used to record and recover authorized gas distribution revenue requirements and certain other authorized gas distribution-related costs. Similar to the utility generation and the distribution revenue adjustment mechanism balancing accounts discussed above, the recovery of these revenue requirements is decoupled from the volume of sales; therefore, the Utility recognizes revenue evenly over the year, even though the level of cash collected from customers fluctuates depending on the volume of gas sales. During the colder months of winter, there is generally an over-collection in this balancing account primarily due to higher natural gas sales. During the warmer months of summer, there is generally an under-collection primarily due to lower natural gas sales.

The ERBs balancing account is used to record and refund to customers the net refunds, claim offsets, and other credits received by the Utility from electricity suppliers related to Chapter 11 disputed claims and to record and recover authorized ERB servicing costs. (See Note 13 below.)

The Utility is generally authorized to recover 100% of its prudently incurred electric energy procurement costs. The Utility tracks energy procurement costs in balancing accounts and files annual forecasts of energy procurement costs that it expects to incur over the following year. The Utility's energy rates are set to recover such expected costs.

The Department of Energy balancing account is used to record and refund to customers the amounts received from the U.S. Department of Energy ("DOE") during 2012 for a settlement agreement related to spent nuclear fuel storage costs incurred by the Utility.

## NOTE 4: DEBT

### Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

| | December 31, | |
|---|---|---|
| **(in millions)** | **2012** | **2011** |
| **PG&E Corporation** | | |
| Senior notes, 5.75%, due 2014 | 350 | 350 |
| Unamortized discount | - | (1) |
| **Total senior notes** | **350** | **349** |
| **Total PG&E Corporation long-term debt** | **350** | **349** |
| **Utility** | | |
| Senior notes: | | |
| 6.25% due 2013 | 400 | 400 |
| 4.80% due 2014 | 1,000 | 1,000 |
| 5.625% due 2017 | 700 | 700 |
| 8.25% due 2018 | 800 | 800 |
| 3.50% due 2020 | 800 | 800 |
| 4.25% due 2021 | 300 | 300 |
| 3.25% due 2021 | 250 | 250 |
| 2.45% due 2022 | 400 | - |
| 6.05% due 2034 | 3,000 | 3,000 |
| 5.80% due 2037 | 950 | 950 |
| 6.35% due 2038 | 400 | 400 |
| 6.25% due 2039 | 550 | 550 |
| 5.40% due 2040 | 800 | 800 |
| 4.50% due 2041 | 250 | 250 |
| 4.45% due 2042 | 400 | - |
| 3.75% due 2042 | 350 | - |
| Less: current portion | (400) | - |
| Unamortized discount, net of premium | (51) | (51) |
| **Total senior notes, net of current portion** | **10,899** | **10,149** |
| Pollution control bonds: | | |
| Series 1996 C, E, F, 1997 B, variable rates (1) , due 2026 (2) | 614 | 614 |
| Series 2004 A-D, 4.75%, due 2023 (3) | 345 | 345 |
| Series 2009 A-D, variable rates (4) , due 2016 and 2026 (5) | 309 | 309 |
| Series 2010 E, 2.25%, due 2026 (6) | - | 50 |
| Less: current portion | - | (50) |
| **Total pollution control bonds** | **1,268** | **1,268** |
| **Total Utility long-term debt, net of current portion** | **12,167** | **11,417** |
| **Total consolidated long-term debt, net of current portion** | **$ 12,517** | **$ 11,766** |

At December 31, 2012, interest rates on these bonds and the related loans ranged from 0.10% to 0.14%.

(2) Each series of these bonds is supported by a separate letter of credit that expires on May 31, 2016. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(3) The Utility has obtained credit support from an insurance company for these bonds.

(4) At December 31, 2012, interest rates on these bonds and the related loans ranged from 0.05% to 0.11%.

(5) Each series of these bonds is supported by a separate direct-pay letter of credit that expires on May 31, 2016. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

(6) These bonds bore interest at 2.25% per year through April 1, 2012; and were subject to mandatory tender on April 2, 2012. The Utility repurchased these bonds on April 2, 2012 and continues to hold them.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. All of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant and were issued as "exempt facility bonds" within the meaning of the Internal Revenue Code of 1954 ("Code"), as amended. In 1999, the Utility sold the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

**Repayment Schedule**

PG&E Corporation's and the Utility's combined aggregate debt principal repayment amounts at December 31, 2012 are reflected in the table below:

| (in millions, except interest rates) | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest rate | - | 5.75% | - | - | - | - | 5.75% |
| Fixed rate obligations | $ - | $ 350 | $ - | $ - | $ - | $ - | $ 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | 6.25% | 4.80% | - | - | 5.63% | 5.45% | 5.43% |
| Fixed rate obligations | $ 400 | $ 1,000 | $ - | $ - | $ 700 | $ 9,595 | $ 11,695 |
| Variable interest rate as of December 31, 2012 | - | - | - | 0.11% | - | - | 0.11% |
| Variable rate obligations | $ - | $ - | $ - | $ 923[(1)] | $ - | $ - | $ 923 |
| **Total consolidated debt** | **$ 400** | **$ 1,350** | **$ -** | **$ 923** | **$ 700** | **$ 9,595** | **$ 12,968** |

(1) These bonds, due in 2016 and 2026, are backed by letters of credit that expire on May 31, 2016.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings on its revolving credit facilities and commercial paper program at December 31, 2012:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Borrowings | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|---|
| PG&E Corporation | May 2016 | $ 300[(1)] | $ - | $ 120 | $ - | $ 180 |
| Utility | May 2016 | 3,000[(2)] | 266 | - | 370[(3)] | 2,364[(3)] |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 266** | **$ 120** | **$ 370** | **$ 2,544** |

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
(3) The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2012, the average outstanding borrowings on PG&E Corporation's revolving credit facility was $21 million and the maximum outstanding balance during the year was $120 million. For 2012, the Utility's average outstanding commercial paper balance was $665 million and the maximum outstanding balance during the year was $1.4 billion.

***Revolving Credit Facilities***

PG&E Corporation has a $300 million revolving credit facility with a syndicate of lenders. The Utility has a $3.0 billion revolving credit facility with a syndicate of lenders. The revolving credit facilities have terms of five years and all amounts are due and payable on the facilities' termination date, May 31, 2016. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for additional periods. The revolving credit facilities may be used for working capital and other corporate purposes. The Utility's revolving credit facility may also be used for the repayment of commercial paper.

Provided certain conditions are met, PG&E Corporation and the Utility have the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the revolving credit facilities by up to $100 million and $500 million, respectively, in the aggregate for all such increases.

Borrowings under the revolving credit facilities (other than swingline loans) bear interest based, at PG&E Corporation's and the Utility's election, on (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the federal funds rate, or the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. PG&E Corporation and the Utility also will pay a facility fee on the total commitments of the lenders under the revolving credit facilities. The applicable margins and the facility fees will be based on PG&E Corporation's and the Utility's senior unsecured debt ratings issued by Standard & Poor's Rating Services and Moody's Investor Service. Facility fees are payable quarterly in arrears.

The revolving credit facilities include usual and customary covenants for revolving credit facilities of this type, including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. At December 31, 2012, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

***Commercial Paper Program***

The Utility has a $1.75 billion commercial paper program, the borrowings from which are used primarily to fund temporary financing needs. Liquidity support for these borrowings is provided by available capacity under the Utility's revolving credit facilities, as described above. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. At December 31, 2012, the average yield on outstanding commercial paper was 0.36%.

***Other Short-term Borrowings***

In November 2011, the Utility issued $250 million principal amount of Floating Rate Senior Notes which were due and repaid in November 2012. For the years ended December 31, 2012 and 2011, the average interest rate on the Floating Rate Senior Notes was 0.92% and 0.94%, respectively.

**NOTE 5: ENERGY RECOVERY BONDS**

In 2005, PERF issued two series of ERBs. The proceeds of the ERBs were used by PERF to purchase from the Utility the right known as "recovery property" to be paid a specific amount from a dedicated rate component. The first series of ERBs included five classes aggregating to a $1.9 billion principal amount. The proceeds of the first series of ERBs were paid by PERF to the Utility and used by the Utility to refinance the remaining unamortized after-tax balance of the regulatory asset established under the Chapter 11 Settlement Agreement. The second series of ERBs included three classes aggregating to an $844 million principal amount. The proceeds of the second series of ERBs were paid by PERF to the Utility and used to pre-fund the Utility's tax liability for bond-related charges collected from customers.

At December 31, 2011, the total amount of ERB principal outstanding was $423 million. The ERBs were paid in full when the final class matured on December 25, 2012.

## NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION

### PG&E Corporation

PG&E Corporation had 430,718,293 shares of common stock outstanding at December 31, 2012. During 2012, PG&E Corporation issued 6,803,101 shares of its common stock under its 401(k) plan, its Dividend Reinvestment and Stock Purchase Plan, and its share-based compensation plans, generating $263 million of cash.

In November 2011, PG&E Corporation entered into an Equity Distribution Agreement providing for the sale of PG&E common stock having an aggregate gross sales price of up to $400 million. Sales of the shares are made by means of ordinary brokers' transactions on the New York Stock Exchange, or in such other transactions as agreed upon by PG&E Corporation and the sales agents and in conformance with applicable securities laws. During 2012, PG&E Corporation sold 5,446,760 shares of its common stock under the Equity Distribution Agreement for cash proceeds of $234 million, net of fees. As of December 31, 2012, PG&E Corporation had the ability to issue an additional $64 million of its common stock under the November 2011 Equity Distribution Agreement. In March 2012, PG&E Corporation sold 5,900,000 shares of its common stock in an underwritten public offering for cash proceeds of $254 million, net of fees and commissions.

### Utility

As of December 31, 2012, PG&E Corporation held all of the Utility's outstanding common stock.

### Dividends

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. In February, June, September, and December, 2012, the Board of Directors of PG&E Corporation declared a quarterly dividend of $0.455 per share.

PG&E Corporation and the Utility each have revolving credit facilities that require the respective company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio for PG&E Corporation, no amount of PG&E Corporation's reinvested earnings was restricted at December 31, 2012. Based on the calculation of this ratio for the Utility, $1.1 billion of the Utility's reinvested earnings was restricted at December 31, 2012. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average. At December 31, 2012, the Utility was required to maintain reinvested earnings of $6.3 billion as equity to meet this requirement.

In addition, to comply with the revolving credit facility's 65% ratio requirement and the CPUC's requirement to maintain a 52% equity component, $7.0 billion and $12.2 billion of the Utility's net assets, respectively, were restricted at December 31, 2012 and could not be transferred to PG&E Corporation in the form of cash dividends. As a holding company, PG&E Corporation depends on cash distributions from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

**Long-Term Incentive Plan**

The PG&E Corporation 2006 Long-Term Incentive Plan ("2006 LTIP") permits the award of various forms of incentive awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock units ("RSUs"), performance shares, deferred compensation awards, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive share-based awards under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) has been reserved for issuance under the 2006 LTIP, of which 4,548,119 shares were available for award at December 31, 2012.

The following table provides a summary of total compensation expense for PG&E Corporation for share-based incentive awards for 2012, 2011, and 2010:

| **(in millions)** | **2012** | **2011** | **2010** |
|---|---|---|---|
| Restricted stock units | $ 31 | $ 22 | $ 9 |
| Other share-based compensation | - | 1 | 14 |
| Performance shares: | | | |
| Equity awards | 26 | 16 | 11 |
| Liability awards | - | (13) | 22 |
| Total compensation expense (pre-tax) | **$ 57** | **$ 26** | **$ 56** |
| Total compensation expense (after-tax) | **$ 34** | **$ 16** | **$ 33** |

There were no significant share-based compensation costs capitalized during 2012, 2011, and 2010. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

Each RSU represents one hypothetical share of PG&E Corporation common stock. RSUs generally vest in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Vested RSUs are settled in shares of PG&E Corporation common stock. Additionally, upon settlement, RSU recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant. RSU expense is recognized ratably over the requisite service period based on the fair values determined, except for the expense attributable to awards granted to retirement-eligible participants, which is recognized on the date of grant.

The weighted average grant-date fair value per RSUs granted during 2012, 2011, and 2010 was $42.17, $45.10, and $42.97, respectively. The total fair value of RSUs that vested during 2012, 2011, and 2010 was $18 million, $11 million, and $5 million, respectively. The tax benefit from RSUs that vested during 2012, 2011, and 2010 was not material. As of December 31, 2012, $44 million of total unrecognized compensation costs related to nonvested RSUs was expected to be recognized over the remaining weighted average period of 2.19 years.

The following table summarizes RSU activity for 2012:

| | **Number of Restricted Stock Units** | **Weighted Average Grant-Date Fair Value** |
|---|---|---|
| Nonvested at January 1 | 1,626,048 | $ 42.57 |
| Granted | 923,001 | $ 42.17 |
| Vested | (424,034) | $ 41.88 |
| Forfeited | (55,724) | $ 42.64 |
| Nonvested at December 31 | **2,069,291** | $ 42.52 |

### *Performance Shares*

In 2012, PG&E Corporation granted 834,420 contingent performance shares to eligible employees. Performance shares vest after three years of service. Performance shares granted in 2012, 2011, and 2010 are settled in shares of PG&E Corporation common stock and are classified as share-based equity awards. Performance-based awards granted prior to 2010 are settled in cash and classified as a liability. The amount of common stock (or cash with respect to grants before 2010) that recipients are entitled to receive, if any, will be determined based on PG&E Corporation's annual total shareholder return relative to the performance of a specified group of peer companies for the applicable three-year performance period. Total compensation expense for performance shares is based on the grant-date fair value, which is determined using a Monte Carlo simulation valuation model. Performance share expense is recognized ratably over the requisite service period based on the fair values determined, except for the expense attributable to awards granted to retirement-eligible participants, which is recognized on the date of grant. Dividend equivalents on performance shares, if any, will be paid in cash upon the vesting date based on the amount of common stock to which the recipients are entitled.

The weighted average grant-date fair value for performance shares granted during 2012, 2011, and 2010 was $41.93, $33.91, and $35.60 respectively. There was no tax benefit associated with performance shares that vested during 2012, 2011, and 2010, as awards that settle in cash have no tax impact, and awards that settle in shares do not generate a tax benefit until vested. The performance shares awarded in March 2010 will vest in March 2013. As of December 31, 2012, $29 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted average period of 1.28 years.

The following table summarizes performance shares classified as equity awards activity for 2012:

| | Number of Performance Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,325,406 | $ 34.64 |
| Granted | 834,420 | $ 41.93 |
| Vested | (425) | $ 34.86 |
| Forfeited [1] | (661,928) | $ 35.71 |
| Nonvested at December 31 | **1,497,473** | $ 38.15 |

[1] Includes performance shares that expired with zero value as performance targets were not met.

## NOTE 7: PREFERRED STOCK

### PG&E Corporation

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

### Utility

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. The Utility specifies that 5,784,825 shares of the $25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. All remaining shares of preferred stock may be issued as redeemable or nonredeemable preferred stock.

The following table summarizes the Utility's outstanding preferred stock, none of which had mandatory redemption provisions at December 31, 2012 and 2011:

| (in millions, except share amounts, redemption price, and par value) | Shares Outstanding | Redemption Price | Balance |
|---|---|---|---|
| **Nonredeemable $25 par value preferred stock** | | | |
| 5.00% Series | 400,000 | N/A | $ 10 |
| 5.50% Series | 1,173,163 | N/A | 30 |
| 6.00% Series | 4,211,662 | N/A | 105 |
| **Total nonredeemable preferred stock** | **5,784,825** | | **$ 145** |
| | | | |
| **Redeemable $25 par value preferred stock** | | | |
| 4.36% Series | 418,291 | $ 25.75 | $ 11 |
| 4.50% Series | 611,142 | 26.00 | 15 |
| 4.80% Series | 793,031 | 27.25 | 20 |
| 5.00% Series | 1,778,172 | 26.75 | 44 |
| 5.00% Series A | 934,322 | 26.75 | 23 |
| **Total redeemable preferred stock** | **4,534,958** | | **$ 113** |
| **Preferred stock** | | | **$ 258** |

At December 31, 2012, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2012, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. During each of 2012, 2011, and 2010 the Utility paid $14 million of dividends on preferred stock.

**NOTE 8: EARNINGS PER SHARE**

PG&E Corporation's basic earnings per common share ("EPS") is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2012 and 2011.

| | Year Ended December 31, | |
|---|---|---|
| **(in millions, except per share amounts)** | **2012** | **2011** |
| **Income available for common shareholders** | $ 816 | $ 844 |
| **Weighted average common shares outstanding, basic** | 424 | 401 |
| Add incremental shares from assumed conversions: | | |
| Employee share-based compensation | 1 | 1 |
| **Weighted average common share outstanding, diluted** | 425 | 402 |
| **Total earnings per common share, diluted** | **$ 1.92** | **$ 2.10** |

For 2010, PG&E Corporation calculated EPS using the "two-class" method because PG&E Corporation's convertible subordinated notes that were outstanding prior to June 29, 2010 were considered to be participating securities. In applying the two-class method, undistributed earnings were allocated to both common shares and participating securities. In calculating diluted EPS for 2010, PG&E Corporation applied the "if-converted" method to reflect the dilutive effect of the convertible subordinated notes to the extent that the impact was dilutive when compared to basic EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating basic and diluted EPS for 2010:

| | Year Ended December 31, 2010 | |
|---|---|---|
| **(in millions, except per share amounts)** | **Basic** | **Diluted** |
| **Income available for common shareholders** | $ 1,099 | $ 1,099 |
| Less: distributed earnings to common shareholders | 706 | - |
| **Undistributed earnings** | **$ 393** | **$ 1,099** |
| **Allocation of earnings to common shareholders** | | |
| Distributed earnings to common shareholders | $ 706 | $ - |
| Undistributed earnings allocated to common shareholders | 385 | 1,099 |
| Add: Interest expense on convertible subordinated notes, net of tax | - | 8 |
| **Total common shareholders earnings and assumed conversion** | **$ 1,091** | **$ 1,107** |
| **Weighted average common shares outstanding** | 382 | 382 |
| Add incremental shares from assumed conversions: | | |
| Convertible subordinated notes | 8 | 8 |
| Employee share-based compensation | - | 2 |
| **Weighted average common shares outstanding and participating securities** | **390** | **392** |
| **Net earnings per common share, basic** | | |
| Distributed earnings, basic [1] | $ 1.85 | $ - |
| Undistributed earnings | 1.01 | 2.82 |
| **Total** | **$ 2.86** | **$ 2.82** |

[1] Distributed earnings, basic may differ from actual per share amounts paid as dividends, as the EPS computation under GAAP requires the use of the weighted average, rather than the actual, number of shares outstanding.

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

## NOTE 9: INCOME TAXES

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| **(in millions)** | **2012** | **2011** | **2010** | **2012** | **2011** | **2010** |
| Current: | | | | | | |
| Federal | $ (74) | $ (77) | $ (12) | $ (52) | $ (83) | $ (54) |
| State | 33 | 152 | 130 | 41 | 161 | 134 |
| Deferred: | | | | | | |
| Federal | 374 | 504 | 525 | 404 | 534 | 589 |
| State | (92) | (135) | (91) | (91) | (128) | (90) |
| Tax credits | (4) | (4) | (5) | (4) | (4) | (5) |
| **Income tax provision** | **$ 237** | **$ 440** | **$ 547** | **$ 298** | **$ 480** | **$ 574** |

The following table describes net deferred income tax liabilities:

| (in millions) | PG&E Corporation 2012 | PG&E Corporation 2011 | Utility 2012 | Utility 2011 |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| **Deferred income tax assets:** | | | | |
| Customer advances for construction | $ 101 | $ 108 | $ 101 | $ 108 |
| Reserve for damages | 175 | 243 | 175 | 243 |
| Environmental reserve | 97 | 157 | 97 | 157 |
| Compensation | 229 | 310 | 179 | 258 |
| Net operating loss carry forward | 938 | 728 | 736 | 567 |
| Other | 264 | 217 | 255 | 180 |
| **Total deferred income tax assets** | **$ 1,804** | **$ 1,763** | **$ 1,543** | **$ 1,513** |
| **Deferred income tax liabilities:** | | | | |
| Regulatory balancing accounts | $ 256 | $ 643 | $ 256 | $ 643 |
| Property related basis differences | 7,449 | 6,544 | 7,447 | 6,536 |
| Income tax regulatory asset | 663 | 588 | 663 | 588 |
| Other | 173 | 192 | 99 | 105 |
| **Total deferred income tax liabilities** | **$ 8,541** | **$ 7,967** | **$ 8,465** | **$ 7,872** |
| **Total net deferred income tax liabilities** | **$ 6,737** | **$ 6,204** | **$ 6,922** | **$ 6,359** |
| **Classification of net deferred income tax liabilities:** | | | | |
| Included in current liabilities (assets) | $ (11) | $ 196 | $ (17) | $ 199 |
| Included in noncurrent liabilities | 6,748 | 6,008 | 6,939 | 6,160 |
| **Total net deferred income tax liabilities** | **$ 6,737** | **$ 6,204** | **$ 6,922** | **$ 6,359** |

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

| | PG&E Corporation 2012 | PG&E Corporation 2011 | PG&E Corporation 2010 | Utility 2012 | Utility 2011 | Utility 2010 |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| Federal statutory income tax rate | 35.0% | 35.0% | 35.0% | 35.0% | 35.0% | 35.0% |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) | (3.9) | 1.1 | 0.7 | (3.0) | 1.6 | 1.0 |
| Effect of regulatory treatment of fixed asset differences | (4.1) | (4.4) | (3.1) | (3.9) | (4.2) | (3.0) |
| Tax credits | (0.6) | (0.5) | (0.4) | (0.6) | (0.5) | (0.4) |
| Benefit of loss carryback | (0.7) | (1.9) | - | (0.4) | (2.1) | - |
| Non deductible penalties | 0.6 | 6.5 | 0.2 | 0.5 | 6.3 | 0.2 |
| Other, net | (3.8) | (1.5) | 0.8 | (0.8) | 0.1 | 1.1 |
| **Effective tax rate** | **22.5%** | **34.3%** | **33.2%** | **26.8%** | **36.2%** | **33.9%** |

*Unrecognized tax benefits*

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| (in millions) | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Balance at beginning of year** | $ 506 | $ 714 | $ 673 | $ 503 | $ 712 | $ 652 |
| Additions for tax position taken during a prior year | 32 | 2 | 27 | 26 | 2 | 27 |
| Reductions for tax position taken during a prior year | (13) | (198) | (20) | (10) | (196) | - |
| Additions for tax position taken during the current year | 67 | 3 | 89 | 67 | - | 87 |
| Settlements | (11) | (15) | (55) | (11) | (15) | (54) |
| **Balance at end of year** | **$ 581** | **$ 506** | **$ 714** | **$ 575** | **$ 503** | **$ 712** |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2012 for PG&E Corporation and the Utility was $18 million, with the remaining balance representing the potential deferral of taxes to later years.

PG&E Corporation and the Utility recognize accrued interest related to unrecognized tax benefits as income tax expense in the Consolidated Statements of Income. Interest income and interest expense for the years ended December 31, 2012, December 31, 2011, and December 31, 2010 were immaterial.

As of December 31, 2012 and December 31, 2011, PG&E Corporation and the Utility had receivables for accrued interest income. The amounts of these receivables were immaterial.

The Internal Revenue Service ("IRS") is working with the utility industry to finalize guidance on what is a repair deduction for tax purposes for the natural gas transmission, natural gas distribution, and electric generation businesses. PG&E Corporation and the Utility expect the IRS to release this guidance in the first half of 2013. PG&E Corporation and the Utility expect the unrecognized tax benefits may change significantly within the next 12 months.

The IRS is auditing a 2008 accounting method change of the Utility to accelerate the amount of deductible repairs. The audit is expected to be completed in 2013. The resolution of the audit could result in a significant change in unrecognized tax benefit. However, PG&E Corporation and the Utility cannot estimate the change of unrecognized tax benefits related to the items discussed above.

***Tax settlements and years that remain subject to examination***

In 2008, PG&E Corporation began participating in the Compliance Assurance Process ("CAP"), a real-time IRS audit intended to expedite resolution of tax matters. The CAP audit culminates with a letter from the IRS indicating its acceptance of the return. The IRS partially accepted the 2008 return, withholding two matters for further review. In December 2010, the IRS accepted the 2009 tax return without change. In September 2011, the IRS partially accepted the 2010 return, withholding two matters for further review. In September 2012, the IRS partially accepted the 2011 return, withholding several matters for future review.

The most significant of the matters withheld for further review in each of these years relates to a tax accounting method change of the Utility related to repairs. The IRS has not completed its review of these claims.

***Loss carry forwards***

As of December 31, 2012, PG&E Corporation had approximately $2.1 billion of federal net operating loss carry forwards and $12 million of tax credit carry forwards, which will expire between 2029 and 2032. In addition, PG&E Corporation had approximately $128 million of loss carry forwards related to charitable contributions, which will expire between 2013 and 2017. PG&E Corporation believes it is more likely than not the tax benefits associated with the federal operating loss, charitable contributions, and tax credits can be realized within the carry forward periods, therefore no valuation allowance was recognized as of December 31, 2012. As of December 31, 2012, PG&E Corporation had approximately $19 million of federal net operating loss carry forwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

## NOTE 10: DERIVATIVES

### Use of Derivative Instruments

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including:

- forward contracts that commit the Utility to purchase a commodity in the future;
- swap agreements and futures contracts that require payments to or from counterparties based upon the difference between two prices for a predetermined contractual quantity; and
- option contracts that provide the Utility with the right to buy a commodity at a predetermined price and option contracts that require payments from counterparties if market prices exceed a predetermined price.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. As long as the current ratemaking mechanism discussed above remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives, the Utility expects to recover fully, in rates, all costs related to derivatives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. (See Note 3 above.) Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Derivatives that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered are eligible for the normal purchase and sale exception. The fair value of derivatives that are eligible for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets.

***Electricity Procurement***

The Utility enters into third-party power purchase agreements for electricity to meet customer needs. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivatives. The Utility elects the normal purchase and sale exception for eligible derivatives.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce volatility in customer rates, the Utility may enter into financial swap and/or financial option contracts to effectively fix and/or cap the price of future purchases and reduce cash flow variability associated with fluctuating electricity prices. These financial contracts are considered derivatives.

*Electric Transmission Congestion Revenue Rights*

The California electric transmission grid, controlled by the California Independent System Operator ("CAISO"), is subject to transmission constraints when there is insufficient transmission capacity to supply the market. The CAISO imposes congestion charges on market participants to manage transmission congestion. The revenue generated from congestion charges is allocated to holders of congestion revenue rights ("CRRs"). CRRs allow market participants to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load-serving entities, such as the Utility, are allocated CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (in which CRRs are priced at market and available to all market participants). The Utility participates in the allocation and auction phases of the annual and monthly CRR processes. CRRs are considered derivatives.

*Natural Gas Procurement (Electric Fuels Portfolio)*

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through physical natural gas commodity purchases to fuel natural gas generating facilities, and electricity procurement contracts indexed to natural gas prices. To reduce the volatility in customer rates, the Utility may enter into financial swap contracts or financial option contracts, or both. The Utility also enters into fixed-price forward contracts for natural gas to reduce future cash flow variability from fluctuating natural gas prices. These instruments are considered derivatives.

*Natural Gas Procurement (Core Gas Supply Portfolio)*

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its residential and smaller commercial customers known as "core" customers. The Utility does not procure natural gas for industrial and large commercial, or "non-core," customers. Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of natural gas may be purchased or sold in the multi-month, monthly, and to a lesser extent, daily spot market to balance such seasonal supply and demand. The Utility purchases financial instruments, such as swaps and options, as part of its core winter hedging program in order to manage customer exposure to high natural gas prices during peak winter months. These financial instruments are considered derivatives.

**Volume of Derivative Activity**

At December 31, 2012, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

| | | Contract Volume (1) | | | |
|---|---|---|---|---|---|
| **Underlying Product** | **Instruments** | **Less Than 1 Year** | **1 Year or Greater but Less Than 3 Years** | **3 Years or Greater but Less Than 5 Years** | **5 Years or Greater (2)** |
| Natural Gas (3) (MMBtus (4)) | Forwards and Swaps | 329,466,510 | 98,628,398 | 5,490,000 | - |
| | Options | 221,587,431 | 216,279,767 | 10,050,000 | - |
| Electricity (Megawatt-hours) | Forwards and Swaps | 2,537,023 | 3,541,046 | 2,009,505 | 2,538,718 |
| | Options | - | 239,015 | 239,233 | 119,508 |
| | Congestion Revenue Rights | 74,198,690 | 74,187,803 | 74,240,147 | 25,699,804 |

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.

(2) Derivatives in this category expire between 2018 and 2023.

(3) Amounts shown are for the combined positions of the electric fuels and core gas portfolios.

(4) Million British Thermal Units.

At December 31, 2011, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

| | | Contract Volume [1] | | | |
|---|---|---|---|---|---|
| **Underlying Product** | **Instruments** | **Less Than 1 Year** | **1 Year or Greater but Less Than 3 Years** | **3 Years or Greater but Less Than 5 Years** | **5 Years or Greater [2]** |
| Natural Gas [3] (MMBtus [4]) | Forwards and Swaps | 500,375,394 | 212,088,902 | 6,080,000 | - |
| | Options | 257,766,990 | 336,543,013 | - | - |
| Electricity (Megawatt-hours) | Forwards and Swaps | 4,718,568 | 5,206,512 | 2,142,024 | 3,754,872 |
| | Options | 1,248,000 | 132,048 | 264,348 | 264,096 |
| | Congestion Revenue Rights | 84,247,502 | 72,882,246 | 72,949,250 | 61,673,535 |

[1] Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
[2] Derivatives in this category expire between 2017 and 2022.
[3] Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
[4] Million British Thermal Units .

**Presentation of Derivative Instruments in the Financial Statements**

In PG&E Corporation's and the Utility's Consolidated Balance Sheets, derivatives are presented on a net basis by counterparty where the right and the intention to offset exists under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At December 31, 2012, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 48 | $ (25) | $ 36 | $ 59 |
| Other noncurrent assets – other | 99 | (11) | - | 88 |
| Current liabilities – other | (255) | 25 | 115 | (115) |
| Noncurrent liabilities – other | (221) | 11 | 14 | (196) |
| **Total commodity risk** | **$ (329)** | **$ -** | **$ 165** | **$ (164)** |

At December 31, 2011, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 54 | $ (39) | $ 103 | $ 118 |
| Other noncurrent assets – other | 113 | (59) | - | 54 |
| Current liabilities – other | (489) | 39 | 274 | (176) |
| Noncurrent liabilities – other | (398) | 59 | 101 | (238) |
| **Total commodity risk** | **$ (720)** | **$ -** | **$ 478** | **$ (242)** |

Gains and losses recorded on PG&E Corporation's and the Utility's derivatives were as follows:

| (in millions) | Commodity Risk<br>For the year ended December 31,<br>2012 | 2011 | 2010 |
|---|---|---|---|
| Unrealized gain/(loss) - regulatory assets and liabilities [1] | $ 391 | $ 21 | $ (260) |
| Realized loss - cost of electricity [2] | (486) | (558) | (573) |
| Realized loss - cost of natural gas [2] | (38) | (106) | (79) |
| **Total commodity risk** | **$ (133)** | **$ (643)** | **$ (912)** |

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.

[2] These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2012, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| (in millions) | Balance at December 31,<br>2012 | 2011 |
|---|---|---|
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (266) | $ (611) |
| Related derivatives in an asset position | 59 | 86 |
| Collateral posting in the normal course of business related to these derivatives | 103 | 250 |
| **Net position of derivative contracts/additional collateral posting requirements [1]** | **$ (104)** | **$ (275)** |

[1] This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

## NOTE 11: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, and price risk management instruments at fair value. Fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. A three-tier fair value hierarchy is established as a basis for considering such assumptions and for inputs used in the valuation methodologies in measuring fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts are held by PG&E Corporation and not the Utility):

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2012 | | | | |
| (in millions) | Level 1 | Level 2 | Level 3 | Netting [(1)] | Total |
| **Assets:** | | | | | |
| Money market investments | $ 209 | $ - | $ - | $ - | **$ 209** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 21 | - | - | - | **21** |
| U.S. equity securities | 940 | 9 | - | - | **949** |
| Non-U.S. equity securities | 379 | - | - | - | **379** |
| U.S. government and agency securities | 681 | 139 | - | - | **820** |
| Municipal securities | - | 59 | - | - | **59** |
| Other fixed-income securities | - | 173 | - | - | **173** |
| Total nuclear decommissioning trusts [(2)] | **2,021** | **380** | **-** | **-** | **2,401** |
| Price risk management instruments (Note 10) | | | | | |
| Electricity | 1 | 60 | 80 | 6 | **147** |
| Gas | - | 5 | 1 | (6) | **-** |
| Total price risk management instruments | **1** | **65** | **81** | **-** | **147** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 30 | - | - | **30** |
| Life insurance contracts | - | 72 | - | - | **72** |
| Total rabbi trusts | **-** | **102** | **-** | **-** | **102** |
| Long-term disability trust | | | | | |
| Money market investments | 10 | - | - | - | **10** |
| U.S. equity securities | - | 14 | - | - | **14** |
| Non-U.S. equity securities | - | 11 | - | - | **11** |
| Fixed-income securities | - | 136 | - | - | **136** |
| Total long-term disability trust | 10 | 161 | - | - | **171** |
| **Total assets** | **$ 2,241** | **$ 708** | **$ 81** | **$ -** | **$ 3,030** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 10) | | | | | |
| Electricity | $ 155 | $ 144 | $ 160 | $ (156) | **$ 303** |
| Gas | 8 | 9 | - | (9) | **8** |
| **Total liabilities** | **$ 163** | **$ 153** | **$ 160** | **$ (165** | **$ 311** |

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Excludes $240 million at December 31, 2012 primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2011 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Money market investments | $ 206 | $ - | $ - | $ - | **$ 206** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 24 | - | - | - | **24** |
| U.S. equity securities | 841 | 8 | - | - | **849** |
| Non-U.S. equity securities | 323 | - | - | - | **323** |
| U.S. government and agency securities | 720 | 156 | - | - | **876** |
| Municipal securities | - | 58 | - | - | **58** |
| Other fixed-income securities | - | 99 | - | - | **99** |
| Total nuclear decommissioning trusts [2] | **1,908** | **321** | **-** | **-** | **2,229** |
| Price risk management instruments (Note 10) | | | | | |
| Electricity | - | 92 | 69 | 8 | **169** |
| Gas | - | 6 | - | (3) | **3** |
| Total price risk management instruments | **-** | **98** | **69** | **5** | **172** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 25 | - | - | **25** |
| Life insurance contracts | - | 67 | - | - | **67** |
| Total rabbi trusts | **-** | **92** | **-** | **-** | **92** |
| Long-term disability trust | | | | | |
| Money market investments | 13 | - | - | - | **13** |
| U.S. equity securities | - | 15 | - | - | **15** |
| Non-U.S. equity securities | - | 9 | - | - | **9** |
| Fixed-income securities | - | 145 | - | - | **145** |
| Total long-term disability trust | **13** | **169** | **-** | **-** | **182** |
| **Total assets** | **$ 2,127** | **$ 680** | **$ 69** | **$ 5** | **$ 2,881** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 10) | | | | | |
| Electricity | $ 411 | $ 289 | $ 143 | $ (441) | **$ 402** |
| Gas | 31 | 13 | - | (32) | **12** |
| **Total liabilities** | **$ 442** | **$ 302** | **$ 143** | **$ (473)** | **$ 414** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

[2] Excludes $188 million at December 31, 2011 primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above:

***Money Market Investments***

PG&E Corporation and the Utility invest in money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as U.S. Treasury bills, U.S. agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's and the Utility's investments in these money market funds are valued using unadjusted prices for identical assets in an active market and are thus classified as Level 1. Money market funds are recorded as cash and cash equivalents in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

***Trust Assets***

The assets held by the nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity securities primarily include investments in common stock, which are valued based on unadjusted prices for identical securities in active markets and are classified as Level 1. Equity securities also include commingled funds composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world, which are classified as Level 2. Price quotes for the assets held by these funds are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2. Under a market approach, fair values are determined based on evaluated pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter. (See Note 10 above.)

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available.

Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2. Over-the-counter options are classified as Level 3 and are valued using a standard option pricing model, which includes forward prices for the underlying commodity, time value at a risk-free rate, and volatility. For periods where market data is not available, the Utility extrapolates observable data using internal models.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are valued based on prices observed in the CAISO auction, which are discounted at the risk-free rate. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions. CRRs are classified as Level 3.

**Transfers between Levels**

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. For the year ended December 31, 2012, there were no significant transfer between levels.

At December 31, 2011, the valuation of price risk management over-the-counter forwards and swaps and exchange-traded options incorporated market observable and market corroborated inputs, where certain previously-considered unobservable inputs became observable. Therefore, the Utility transferred these instruments out of Level 3 and into Level 2. There were no significant transfers between Levels 1 and 2 in the year ended December 31, 2011.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's Market and Credit Risk Management department is responsible for determining the fair value of the Utility's price risk management derivatives. Market and Credit Risk Management reports to the Chief Risk Officer of the Utility. Market and Credit Risk Management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments. These models use pricing inputs from brokers and historical data. The Market and Credit Risk Management department and the Controller's organization collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness. Valuation models and techniques are reviewed periodically.

CRRs and power purchase agreements are valued using historical prices or significant unobservable inputs derived from internally developed models. Historical prices include CRR auction prices. Unobservable inputs include forward electricity prices. Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 10 above.)

| **(in millions)** | **Fair Value at December 31, 2012** | | | | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Valuation Technique** | **Unobservable Input** | **Range [(1)]** |
| Congestion revenue rights | $ 80 | $ 16 | Market approach | CRR auction prices | $ (9.04) - 55.15 |
| Power purchase agreements | $ - | $ 145 | Discounted cash flow | Forward prices | $ 8.59 - 62.90 |

(1) [(1)] Represents price per megawatt-hour

**Level 3 Reconciliation**

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2012 and 2011, respectively:

| | **Price Risk Management Instruments** | |
|---|---|---|
| **(in millions)** | **2012** | **2011** |
| Liability balance as of January 1 | **$ (74)** | **$ (399)** |
| Realized and unrealized gains (losses): | | |
| Included in regulatory assets and liabilities or balancing accounts [(1)] | (5) | 122 |
| Transfers out of Level 3 | - | 203 |
| **Liability balance as of December 31** | **$ (79)** | **$ (74)** |

[(1)] Price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2012 and 2011, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bond loan agreements and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2012 and 2011. The fair value of the ERBs issued by PERF was also based on quoted market prices at December 31, 2011.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2012 | | 2011 | |
| **(in millions)** | **Carrying Amount** | **Level 2 Fair Value** | **Carrying Amount** | **Level 2 Fair Value** |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 349 | $ 371 | $ 349 | $ 380 |
| Utility | 11,645 | 13,946 | 10,545 | 12,543 |
| **Energy recovery bonds (Note 5)** | - | - | 423 | 433 |

*Nuclear Decommissioning Trust Investments*

The following table provides a summary of available-for-sale investments held in the Utility's nuclear decommissioning trusts:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value [1] |
|---|---|---|---|---|
| **As of December, 2012** | | | | |
| Money market investments | $ 21 | $ - | $ - | $ 21 |
| Equity securities | | | | |
| U.S. | 331 | 618 | - | 949 |
| Non-U.S. | 199 | 181 | (1) | 379 |
| Debt securities | | | | |
| U.S. government and agency securities | 723 | 97 | - | 820 |
| Municipal securities | 56 | 4 | (1) | 59 |
| Other fixed-income securities | 168 | 5 | - | 173 |
| **Total** | **$ 1,498** | **$ 905** | **$ (2)** | **$ 2,401** |
| **As of December 31, 2011** | | | | |
| Money market investments | $ 24 | $ - | $ - | $ 24 |
| Equity securities | | | | |
| U.S. | 334 | 518 | (3) | 849 |
| Non-U.S. | 194 | 131 | (2) | 323 |
| Debt securities | | | | |
| U.S. government and agency securities | 774 | 102 | - | 876 |
| Municipal securities | 56 | 2 | - | 58 |
| Other fixed-income securities | 96 | 3 | - | 99 |
| **Total** | **$ 1,478** | **$ 756** | **$ (5)** | **$ 2,229** |

[1] Excludes $240 million and $188 million at December 31, 2012 and December 31, 2011, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

| (in millions) | As of December 31, 2012 |
|---|---|
| Less than 1 year | $ 5 |
| 1–5 years | 456 |
| 5–10 years | 218 |
| More than 10 years | 373 |
| **Total maturities of debt securities** | **$ 1,052** |

The following table provides a summary of activity for the debt and equity securities:

| (in millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 1,133 | $ 1,928 | $ 1,405 |
| Gross realized gains on sales of securities held as available-for-sale | 19 | 43 | 42 |
| Gross realized losses on sales of securities held as available-for-sale | (17) | (30) | (11) |

**NOTE 12: EMPLOYEE BENEFIT PLANS**

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees, as well as contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended ("Code"). If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain Code limitations. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans was zero.

**Change in Plan Assets, Benefit Obligations, and Funded Status**

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2012 and 2011:

***Pension Benefits***

| **(in millions)** | **2012** | **2011** |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at January 1** | **$ 10,993** | **$ 10,250** |
| Actual return on plan assets | 1,488 | 1,016 |
| Company contributions | 282 | 230 |
| Benefits and expenses paid | (622) | (503) |
| **Fair value of plan assets at December 31** | **$ 12,141** | **$ 10,993** |
| | | |
| **Change in benefit obligation:** | | |
| **Projected benefit obligation at January 1** | **$ 14,000** | **$ 12,071** |
| Service cost for benefits earned | 396 | 320 |
| Interest cost | 658 | 660 |
| Actuarial loss | 1,099 | 1,450 |
| Plan amendments | 9 | - |
| Transitional costs | 1 | 2 |
| Benefits and expenses paid | (622) | (503) |
| **Projected benefit obligation at December 31 [1]** | **$ 15,541** | **$ 14,000** |
| | | |
| **Funded status:** | | |
| Current liability | $ (6) | $ (5) |
| Noncurrent liability | (3,394) | (3,002) |
| **Accrued benefit cost at December 31** | **$ (3,400)** | **$ (3,007)** |

(1) PG&E Corporation's accumulated benefit obligation was $13,778 million and $12,285 million at December 31, 2012 and 2011, respectively.

*Other Benefits*

| **(in millions)** | **2012** | **2011** |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at January 1** | **$ 1,491** | **$ 1,337** |
| Actual return on plan assets | 191 | 95 |
| Company contributions | 149 | 137 |
| Plan participant contribution | 55 | 52 |
| Benefits and expenses paid | (128) | (130) |
| **Fair value of plan assets at December 31** | **$ 1,758** | **$ 1,491** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at January 1** | **$ 1,885** | **$ 1,755** |
| Service cost for benefits earned | 49 | 42 |
| Interest cost | 83 | 91 |
| Actuarial loss | (23) | 63 |
| Plan amendments | 5 | - |
| Benefits paid | (119) | (130) |
| Federal subsidy on benefits paid | 5 | 12 |
| Plan participant contributions | 55 | 52 |
| **Benefit obligation at December 31** | **$ 1,940** | **$ 1,885** |
| | | |
| **Funded status:** | | |
| Noncurrent liability | $ (181) | $ (394) |
| **Accrued benefit cost at December 31** | **$ (181)** | **$ (394)** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

During 2012, the Utility's defined benefit pension plan was amended to include a new cash balance benefit formula. Eligible employees hired after December 31, 2012 will participate in the cash balance benefit. Eligible employees hired before January 1, 2013 will have a one-time opportunity to elect to participate in the cash balance benefit going forward, beginning on January 1, 2014 or to continue participating in the existing defined benefit plan. As long as pension benefit costs continue to be recoverable through customer rates, PG&E Corporation and the Utility anticipate that this amendment will have no impact on net income.

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2012, 2011, and 2010 was as follows:

***Pension Benefits***

| (in millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Service cost for benefits earned | $ 396 | $ 320 | $ 279 |
| Interest cost | 658 | 660 | 645 |
| Expected return on plan assets | (598) | (669) | (624) |
| Amortization of prior service cost | 20 | 34 | 53 |
| Amortization of unrecognized loss | 123 | 50 | 44 |
| **Net periodic benefit cost** | **599** | **395** | **397** |
| Less: transfer to regulatory account [1] | (301) | (139) | (233) |
| **Total** | **$ 298** | **$ 256** | **$ 164** |

[1] The Utility recorded $301 million, $139 million, and $233 million for the years ended December 31, 2012, 2011, and 2010, respectively, to a regulatory account as the amounts are probable of recovery from customers in future rates

***Other Benefits***

| (in millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Service cost for benefits earned | $ 49 | $ 42 | $ 36 |
| Interest cost | 83 | 91 | 88 |
| Expected return on plan assets | (77) | (82) | (74) |
| Amortization of transition obligation | 24 | 26 | 26 |
| Amortization of prior service cost | 25 | 27 | 25 |
| Amortization of unrecognized loss (gain) | 6 | 4 | 3 |
| **Net periodic benefit cost** | **$ 110** | **$ 108** | **$ 104** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record the net periodic benefit cost for pension benefits and other benefits as a component of accumulated other comprehensive income, net of tax. Net periodic benefit cost is composed of unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax.

Regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between pension expense or income calculated in accordance with GAAP for accounting purposes and pension expense or income for ratemaking, which is based on a funding approach. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income for the pension benefits related to the Utility's defined benefit pension plan. The Utility would record a regulatory liability for a portion of the credit balance in accumulated other comprehensive income, should the other benefits be in an overfunded position. However, this recovery mechanism does not allow the Utility to record a regulatory asset for an underfunded position related to other benefits. Therefore, the charge remains in accumulated other comprehensive income (loss) for other benefits.

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2013 are as follows:

| ***Pension Benefit*** **(in millions)** | |
|---|---|
| Unrecognized prior service cost | $ 20 |
| Unrecognized net loss | 110 |
| **Total** | **$ 130** |

| ***Other Benefits*** **(in millions)** | |
|---|---|
| Unrecognized prior service cost | $ 24 |
| Unrecognized net loss | 6 |
| **Total** | **$ 30** |

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

**Valuation Assumptions**

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

| | **Pension Benefits** | | | **Other Benefits** | | |
|---|---|---|---|---|---|---|
| | **December 31,** | | | **December 31,** | | |
| | **2012** | **2011** | **2010** | **2012** | **2011** | **2010** |
| **Discount rate** | 3.98% | 4.66% | 5.42% | 3.75 - 4.08% | 4.41 - 4.77% | 5.11 - 5.56% |
| **Average rate of future compensation increases** | 4.00% | 5.00% | 5.00% | - | - | - |
| **Expected return on plan assets** | 5.40% | 5.50% | 6.60% | 2.90 - 6.10% | 4.40 - 5.50% | 5.20 - 6.60% |

The assumed health care cost trend rate as of December 31, 2012 was 7.5%, decreasing gradually to an ultimate trend rate in 2018 and beyond of approximately 5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| **(in millions)** | **One-Percentage-Point Increase** | **One-Percentage-Point Decrease** |
|---|---|---|
| Effect on postretirement benefit obligation | $ 108 | $ (111) |
| Effect on service and interest cost | 8 | (8) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 5.4% compares to a ten-year actual return of 10.2%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 648 Aa-grade non-callable bonds at December 31, 2012. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The difference between actual and expected return on plan assets is included in unrecognized gain (loss), and is considered in the determination of future net periodic benefit income (cost). The actual return on plan assets in 2011 exceeded expectations due to a higher than expected return on fixed-income debt investments. The actual return on plan assets in 2012 was in line with expectations.

**Investment Policies and Strategies**

The financial position of PG&E Corporation's and the Utility's funded employee benefit plans is driven by the relationship between plan assets and liabilities. As noted above, the funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs for financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended ("ERISA"). PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trust's fixed-income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage this risk, PG&E Corporation's and the Utility's trusts hold significant allocations to fixed-income investments that include U.S. government securities, corporate securities, and other fixed-income securities. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. The equity investment allocation is implemented through portfolios that include common stock and commingled funds across multiple industry sectors. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, global real estate investment trusts ("REITS"), global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Over the last three years, target allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening future funded status volatility. In 2012, equity index futures were added to maintain existing equity exposure while adding exposure to fixed-income securities. Historically, the equity investment allocation was implemented through diversified U.S. equity, non-U.S. equity, and global portfolios. In 2012, the U.S. equity and non-U.S. equity allocations were eliminated and became a combined global equity allocation.

In accordance with the pension plan's investment guidelines, derivative instruments such as equity-index futures contracts are used primarily to maintain equity and fixed income portfolio exposure consistent with the investment policy and to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also used to hedge a portion of the currency of the global equity investments.

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | **Pension Benefits** | | | **Other Benefits** | | |
|---|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2013** | **2012** | **2011** |
| Global equity securities | 25% | 35% | 5% | 28% | 38% | 3% |
| U.S. equity securities | -% | -% | 26% | -% | -% | 28% |
| Non-U.S. equity securities | -% | -% | 14% | -% | -% | 15% |
| Absolute return | 5% | 5% | 5% | 4% | 4% | 4% |
| Real assets | 10% | 10% | -% | 8% | 8% | -% |
| Extended fixed-income securities | 3% | 3% | -% | -% | -% | -% |
| Fixed-income securities | 57% | 47% | 50% | 60% | 50% | 50% |
| **Total** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |

**Fair Value Measurements**

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2012 and 2011.

| | Fair Value Measurements At December 31, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | | | | 2011 | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Benefits:** | | | | | | | | |
| Money market investments | $ 112 | $ - | $ - | **$ 112** | $ 51 | $ - | $ - | **$ 51** |
| U.S. equity securities | - | - | - | **-** | 273 | 2,161 | - | **2,434** |
| Non-U.S. equity securities | - | - | - | **-** | 131 | 1,363 | - | **1,494** |
| Global equity securities | 402 | 3,017 | - | **3,419** | - | 197 | - | **197** |
| Absolute return | - | - | 513 | **513** | - | - | 487 | **487** |
| Real assets | 525 | - | 285 | **810** | 522 | - | 65 | **587** |
| Fixed-income securities: | | | | | | | | |
| U.S. government | 1,576 | 139 | - | **1,715** | 1,224 | 172 | - | **1,396** |
| Corporate | 3 | 4,275 | 611 | **4,889** | 2 | 3,083 | 585 | **3,670** |
| Other | - | 576 | - | **576** | 1 | 688 | - | **689** |
| **Total** | **$ 2,618** | **$ 8,007** | **$ 1,409** | **$ 12,034** | **$ 2,204** | **$ 7,664** | **$ 1,137** | **$ 11,005** |
| **Other Benefits:** | | | | | | | | |
| Money market investments | $ 77 | $ - | $ - | **$ 77** | $ 48 | $ - | $ - | **$ 48** |
| U.S. equity securities | - | - | - | **-** | 86 | 222 | - | **308** |
| Non-U.S. equity securities | - | - | - | **-** | 79 | 108 | - | **187** |
| Global equity securities | 118 | 397 | - | **515** | - | 19 | - | **19** |
| Absolute return | - | - | 49 | **49** | - | - | 47 | **47** |
| Real assets | 68 | - | 28 | **96** | 31 | - | 6 | **37** |
| Fixed-income securities: | | | | | | | | |
| U.S. government | 148 | 5 | - | **153** | 151 | - | - | **151** |
| Corporate | 9 | 795 | 1 | **805** | - | 681 | 1 | **682** |
| Other | - | 38 | - | **38** | 1 | 44 | - | **45** |
| **Total** | **$ 420** | **$ 1,235** | **$ 78** | **$ 1,733** | **$ 396** | **$ 1,074** | **$ 54** | **$ 1,524** |
| **Total plan assets at fair value** | | | | **$ 13,767** | | | | **$ 12,529** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $132 million and other net liabilities of $45 million at December 31, 2012 and 2011, respectively. These net assets and net liabilities were comprised primarily of cash, accounts receivable, accounts payable, and deferred taxes.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

***Money Market Investments***

Money market investments consist primarily of commingled funds of U.S. government short-term securities that are considered Level 1 assets and valued at the net asset value of $1 per unit. The number of units held by the plan fluctuates based on the unadjusted price changes in active markets for the funds’ underlying assets.

***Equity Securities***

The global equity categories include equity investments in common stock and equity-index futures, and commingled funds comprised of equity across multiple industries and regions of the world. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets. Collateral posted related to these futures consist of money market investments that are considered Level 1 assets. Commingled funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled funds are categorized as Level 2 assets.

***Absolute Return***

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

***Real Assets***

The real asset category includes portfolios of commodities, commodities futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodities, commodities futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets. Collateral posted related to the commodities futures consist of money market investments that are considered Level 1 assets. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models, and valuation inputs that are unobservable and are considered Level 3 assets.

***Fixed-Income***

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments. Commingled funds are considered Level 2 assets. Corporate fixed income also includes insurance contracts for deferred annuities. These investments are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on benchmark yields created using observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and index futures. Collateral posted related to the index futures consist of money market investments that are considered Level 1 assets. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

**Transfers Between Levels**

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. As shown in the table below, transfers out of Level 3 represent assets that were previously classified as Level 3 for which the lowest significant input became observable during the period. No significant transfers between Levels 1 and 2 occurred in the years ended December 31, 2012 and 2011.

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2012 and 2011:

| (in millions) | Pension Benefits | | | | |
|---|---|---|---|---|---|
| | Absolute Return | Corporate Fixed-Income | Other Fixed-Income | Real Assets | Total |
| Balance as of January 1, 2011 | $ 494 | $ 549 | $ 120 | $ - | **$ 1,163** |
| Actual return on plan assets: | | | | | |
| Relating to assets still held at the reporting date | 5 | 57 | (2) | - | **60** |
| Relating to assets sold during the period | 2 | - | 1 | - | **3** |
| Purchases, issuances, sales, and settlements | | | | | |
| Purchases | - | 14 | 2 | 65 | **81** |
| Settlements | (14) | (35) | (58) | - | **(107)** |
| Transfers out of Level 3 | - | - | (63) | - | **(63)** |
| **Balance as of December 31, 2011** | **$ 487** | **$ 585** | **$ -** | **$ 65** | **$ 1,137** |
| Actual return on plan assets: | | | | | |
| Relating to assets still held at the reporting date | 26 | 28 | - | 12 | **66** |
| Relating to assets sold during the period | - | (1) | - | **-** | **(1)** |
| Purchases, issuances, sales, and settlements | | | | | |
| Purchases | - | 12 | - | 208 | **220** |
| Settlements | - | (13) | - | **-** | **(13)** |
| **Balance as of December 31, 2012** | **$ 513** | **$ 611** | **$ -** | **$ 285** | **$ 1,409** |

| (in millions) | Other Benefits | | | | |
|---|---|---|---|---|---|
| | Absolute Return | Corporate Fixed-Income | Other Fixed-Income | Real Assets | Total |
| Balance as of January 1, 2011 | $ 47 | $ 129 | $ 10 | - | **$ 186** |
| Actual return on plan assets: | | | | | |
| Relating to assets still held at the reporting date | 1 | 16 | - | - | **17** |
| Relating to assets sold during the period | - | (2) | - | - | **(2)** |
| Purchases, issuances, sales, and settlements | | | | | |
| Purchases | - | 34 | - | 6 | **40** |
| Settlements | (1) | (30) | (5) | - | **(36)** |
| Transfers out of Level 3 | - | (146) | (5) | - | **(151)** |
| **Balance as of December 31, 2011** | **$ 47** | **$ 1** | **$ -** | **$ 6** | **$ 54** |
| Actual return on plan assets: | | | | | |
| Relating to assets still held at the reporting date | 2 | - | - | 1 | **3** |
| Relating to assets sold during the period | - | - | - | - | **-** |
| Purchases, issuances, sales, and settlements | | | | | |
| Purchases | - | 1 | - | 21 | **22** |
| Settlements | - | (1) | - | - | **(1)** |
| **Balance as of December 31, 2012** | **$ 49** | **$ 1** | **$ -** | **$ 28** | **$ 78** |

There were no transfers out of Level 3 in 2012.

**Cash Flow Information**

***Employer Contributions***

PG&E Corporation and the Utility contributed $282 million to the pension benefit plans and $149 million to the other benefit plans in 2012. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2012. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $109 million to the pension plan and other postretirement benefit plans, respectively, for 2013.

***Benefits Payments and Receipts***

As of December 31, 2012, the estimated benefits PG&E Corporation is expected to pay and federal subsidies it is estimated to receive in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter for PG&E Corporation, are as follows:

| **(in millions)** | **Pension** | **Other** | **Federal Subsidy** |
|---|---|---|---|
| 2013 | $ 581 | $ 108 | $ (6) |
| 2014 | 618 | 112 | (7) |
| 2015 | 656 | 115 | (7) |
| 2016 | 695 | 119 | (8) |
| 2017 | 732 | 124 | (8) |
| 2018 - 2022 | 4,172 | 662 | (42) |

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

**Defined Contribution Benefit Plans**

PG&E Corporation sponsors employee retirement savings plans, including a 401(k) defined contribution savings plan. These plans are qualified under applicable sections of the Code and provide for tax-deferred salary deductions, after-tax employee contributions, and employer contributions. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

| **(in millions)**<br>**Year ended December 31,** | |
|---|---|
| 2012 | $ 67 |
| 2011 | 65 |
| 2010 | 56 |

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

**NOTE 13: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS**

Various electricity suppliers filed claims in the Utility's Chapter 11 proceeding seeking payment for energy supplied to the Utility's customers through the wholesale electricity markets operated by the CAISO and the California Power Exchange ("PX") between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the PX wholesale electricity markets during this period. It is uncertain when all these FERC and judicial proceedings will be finally resolved.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Additional settlement discussions with other electricity suppliers are ongoing. Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers through resolution of the remaining disputed claims, either through settlement or through the conclusion of the various FERC and judicial proceedings, are refunded to customers through rates in future periods.

On April 10, 2012, the Utility received from the PX a letter stating the mutual intent of the CAISO and the PX to offset the Utility's remaining disputed claims with its accounts receivable from the CAISO and the PX. Accordingly, the Utility has presented the net amount of remaining disputed claims and accounts receivable on the Consolidated Balance Sheets at December 31, 2012, reflecting its intent and right to offset these amounts. At December 31, 2011, $494 million was included within accounts receivable – other on the Consolidated Balance Sheets.

The following table presents the changes in the remaining net disputed claims liability, which includes interest:

| **(in millions)** | | |
|---|---|---|
| Balance at December 31, 2011 | $ | 848 |
| Interest accrued | | 27 |
| Less: supplier settlements | | (33) |
| **Balance at December 31, 2012** | **$** | **842** |

At December 31, 2012, the remaining net disputed claims liability consisted of $157 million of remaining net disputed claims (classified on the Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) and $685 million of accrued interest (classified on the Consolidated Balance Sheets within interest payable).

At December 31, 2012 and December 31, 2011, the Utility held $291 million and $320 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

Interest accrues on the remaining net disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates, these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims, the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims and when such interest is paid.

## NOTE 14: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were as follows:

| | **Year Ended December 31,** | | |
|---|---|---|---|
| **(in millions)** | **2012** | **2011** | **2010** |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 7 | $ 6 | $ 7 |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 50 | $ 49 | $ 55 |
| Utility employee benefit due to PG&E Corporation | 51 | 33 | 27 |

At December 31, 2012 and 2011, the Utility had receivables of $19 million and $21 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $17 million and $13 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

**NOTE 15: COMMITMENTS AND CONTINGENCIES**

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to regulatory proceedings, nuclear operations, legal matters, environmental remediation, and guarantees.

**Commitments**

***Third-Party Power Purchase Agreements***

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

The costs incurred for all power purchases were as follows:

| (in millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Qualifying facilities [1] | $ 779 | $ 1,069 | $ 1,164 |
| Renewable energy contracts | 815 | 622 | 573 |
| Other power purchase agreements | 661 | 690 | 657 |

[1] Costs incurred include $ 286 , $297, and $321 attributable to renewable energy contracts with qualifying facilities at December 31, 2012 , 2011 and 2010 , respectively.

*Qualifying Facility Power Purchase Agreements* – Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility ("QF"). QFs include small power production facilities whose primary energy sources are co-generation facilities that produce combined heat and power and renewable generation facilities. To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms and conditions, prices, and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF's electrical output and CPUC-approved energy prices. Capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF exceeds or fails to meet performance requirements specified in the applicable power purchase agreement.

As of December 31, 2012, the Utility had agreements with 180 QFs that are in operation, which expire at various dates between 2013 and 2028.

*Renewable Energy Power Purchase Agreements* – The Utility has entered into various contracts to purchase renewable energy to help the Utility meet California's current renewable portfolio standard ("RPS") requirement. California's RPS program gradually increases the amount of renewable energy that load-serving entities, such as the Utility, must deliver to their customers from an average of at least 20% of their total retail sales in the years 2011-2013 to 33% of their total retail sales in 2021 and thereafter. Generally these agreements include an energy payment based on the electrical output and a fixed price per Megawatt-hour. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities. The table below includes arrangements that have been approved by the CPUC and have completed major milestones with respect to construction. The Utility's commitments for energy payments under these renewable energy agreements are expected to grow significantly, assuming that the facilities are developed timely.

*Other Power Purchase Agreements* – The Utility has entered into several power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility under tolling agreements. The Utility also has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

At December 31, 2012, the undiscounted future expected obligations under power purchase agreements were as follows:

| (in millions) | Qualifying Facility | Renewable (Other than QF) | Other | Total Payments |
|---|---|---|---|---|
| 2013 | $ 892 | $ 1,356 | $ 846 | $ 3,094 |
| 2014 | 914 | 1,843 | 677 | 3,434 |
| 2015 | 727 | 2,038 | 649 | 3,414 |
| 2016 | 618 | 2,054 | 626 | 3,298 |
| 2017 | 490 | 2,053 | 597 | 3,140 |
| Thereafter | 2,238 | 30,958 | 3,322 | 36,518 |
| **Total** | **$ 5,879** | **$ 40,302** | **$ 6,717** | **$ 52,898** |

Some of the power purchase agreements that the Utility entered into with independent power producers that are QFs are treated as capital leases. The following table shows the future fixed capacity payments due under the QF agreements that are treated as capital leases. (These amounts are also included in the table above.) The fixed capacity payments are discounted to their present value in the table below using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

| (in millions) | |
|---|---|
| 2013 | $ 35 |
| 2014 | 27 |
| 2015 | 24 |
| 2016 | 22 |
| 2017 | 18 |
| Thereafter | 20 |
| **Total fixed capacity payments** | **146** |
| Less: amount representing interest | 21 |
| **Present value of fixed capacity payments** | **$ 125** |

Minimum lease payments associated with the lease obligations are included in cost of electricity on PG&E Corporation's and the Utility's Consolidated Statements of Income. The timing of the recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF agreements that are treated as capital leases expire between April 2014 and September 2021.

The present value of the fixed capacity payments due under these agreements is recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets. At December 31, 2012 and 2011, current liabilities – other included $29 million and $36 million, respectively, and noncurrent liabilities – other included $96 million and $212 million, respectively. The corresponding assets at December 31, 2012 and 2011 of $125 million and $248 million including accumulated amortization of $148 million and $160 million, respectively are included in property, plant, and equipment on PG&E Corporation's and the Utility's Consolidated Balance Sheets.

***Natural Gas Supply, Transportation, and Storage Commitments***

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

At December 31, 2012, the Utility's undiscounted future expected payment obligations for natural gas supplies, transportation and storage were as follows:

| (in millions) | | |
|---|---|---|
| 2013 | $ | 707 |
| 2014 | | 208 |
| 2015 | | 192 |
| 2016 | | 152 |
| 2017 | | 108 |
| Thereafter | | 865 |
| **Total** | **$** | **2,232** |

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts less than 1 year, amounted to $1.3 billion in 2012, $1.8 billion in 2011, and $1.6 billion in 2010.

***Nuclear Fuel Agreements***

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from one to 13 years and are intended to ensure long-term nuclear fuel supply. The contracts for uranium and for conversion and enrichment services provide for 100% coverage of reactor requirements through 2020, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2017. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

At December 31, 2012, the undiscounted future expected payment obligations for nuclear fuel were as follows:

| (in millions) | | |
|---|---|---|
| 2013 | $ | 113 |
| 2014 | | 128 |
| 2015 | | 194 |
| 2016 | | 147 |
| 2017 | | 148 |
| Thereafter | | 878 |
| **Total** | **$** | **1,608** |

Payments for nuclear fuel amounted to $118 million in 2012, $77 million in 2011, and $144 million in 2010.

***Other Commitments***

The Utility has other commitments relating to operating leases. At December 31, 2012, the future minimum payments related to these commitments were as follows:

| (in millions) | | |
|---|---|---|
| 2013 | $ | 42 |
| 2014 | | 37 |
| 2015 | | 32 |
| 2016 | | 31 |
| 2017 | | 24 |
| Thereafter | | 206 |
| **Total** | **$** | **372** |

Payments for other commitments relating to operating leases amounted to $32 million in 2012, $27 million in 2011, and $25 million in 2010. PG&E Corporation and the Utility had operating leases on office facilities expiring at various dates from 2013 to 2023. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2% to 5%. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension options ranging between one and five years.

***Underground Electric Facilities***

At December 31, 2012, the Utility was committed to spending approximately $277 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties, and communications utilities involved. The Utility expects to spend $86 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and that the amount of the capital expenditures will be recoverable from customers through rates.

**Contingencies**

**Legal and Regulatory Contingencies**

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations.

PG&E Corporation and the Utility record a provision for a loss when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amounts related to such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability associated with claims and litigation, regulatory proceedings, penalties, and other legal matters (other than the third-party claims, litigation, and investigations related to natural gas matters that are discussed below) totaled $34 million at December 31, 2012 and $52 million at December 31, 2011 and are included in PG&E Corporation's and the Utility's current liabilities – other in the Consolidated Balance Sheets. Except as discussed below, PG&E Corporation and the Utility do not believe that losses associated with legal and regulatory contingencies would have a material impact on their financial condition, results of operations, or cash flows.

**Natural Gas Matters**

On September 9, 2010, an underground 30-inch natural gas transmission pipeline ("Line 132") owned and operated by the Utility, ruptured in a residential area located in the City of San Bruno, California (the "San Bruno accident"). The ensuing explosion and fire resulted in the deaths of eight people, numerous personal injuries, and extensive property damage. Following the San Bruno accident, various regulatory proceedings, investigations, and lawsuits were commenced. The Natural Transportation Safety Board, an independent review panel appointed by the CPUC, and the CPUC's Safety and Enforcement Division ("SED") completed investigations into the causes of the accident, placing the blame primarily on the Utility.

***Pending CPUC Investigations and Enforcement Matters***

The CPUC is conducting three investigations pertaining to the Utility's natural gas operations, which are described below. In 2012, the SED issued reports in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations and recommending that the CPUC impose penalties on the Utility. (See "Penalties Conclusion" below.) Although the Utility, the SED, and other parties have engaged in settlement discussions in an effort to reach a stipulated outcome to resolve the investigations, the parties have not reached an agreement. PG&E Corporation and the Utility are uncertain whether or when any stipulated outcome might be reached. Any agreement regarding a stipulated outcome would be subject to CPUC approval.

The CPUC has concluded evidentiary hearings in each investigation. The CPUC administrative law judges ("ALJs") who oversee the investigations have adopted a revised procedural schedule, including the dates by which the parties' briefs must be submitted. The ALJs have also permitted the other parties (the City of San Bruno, The Utility Reform Network, and the City and County of San Francisco) to separately address in their opening briefs their allegations against the Utility, if any, in addition to the allegations made by the SED. The ALJs have ordered the SED and other parties to file single coordinated briefs to address potential monetary penalties and remedies (which could include remedial operational or policy measures) for all three investigations by April 26, 2013. After briefing has been completed, the ALJs will issue one or more presiding officer's decisions listing the violations determined to have been committed, the amount of penalties, and any required remedial actions. Based on the revised procedural schedule, one or more presiding officer's decisions will be issued by July 23, 2013. The decisions would become the final decisions of the CPUC thirty days after issuance unless the Utility or another party filed an appeal, or a CPUC commissioner requested review of the decision, within such time.

*CPUC Investigation Regarding the Utility's Facilities Records for its Natural Gas Pipelines*

In February 2011, the CPUC commenced an investigation pertaining to safety recordkeeping for Line 132, as well as for the Utility's entire gas transmission system. Among other matters, the investigation will determine whether the San Bruno accident would have been preventable by the exercise of safe procedures and /or accurate and technical recordkeeping in compliance with the law. In March 2012, the SED submitted testimony alleging that the Utility committed numerous violations of applicable laws and regulations based on the findings of the SED's records management consultant and an engineering consultant. Among other findings, the consultants' reports concluded that: the Utility's recordkeeping practices have been deficient and have diminished pipeline safety; the San Bruno accident may have been prevented had the Utility managed its records properly over the years; and that the Utility has been operating, and continues to operate, without a functional integrity management program. The Utility submitted testimony to the CPUC that acknowledged that improvements are needed to its asset management system and recordkeeping practices, but disputed many of the SED's findings and allegations. The CPUC concluded evidentiary hearings in this investigation in January 2013. Briefing on the issue of alleged violations is scheduled to be completed on April 19, 2013.

*CPUC Investigation Regarding the Utility's Class Location Designations for Pipelines*

In November 2011, the CPUC commenced an investigation pertaining to the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density. Under federal and state regulations, the class location designation of a pipeline is based on the types of buildings, population density, or level of human activity near the segment of pipeline, and is used to determine the maximum allowable operating pressure up to which a pipeline can be operated. In its May 2012 investigative report, the SED cited the Utility's admissions in previous reports to the CPUC that it had failed to classify pipeline segments properly and to document past patrols of transmission lines and concluded that these failures resulted in over three thousand violations of state and federal standards. On July 23, 2012, the Utility submitted testimony in response to the SED's report that acknowledged deficiencies in the Utility's past class location and patrol processes and described the efforts to improve those processes. The CPUC concluded evidentiary hearings in this investigation in September 2012 and briefing on the issue of alleged violations has been completed.

*CPUC Investigation Regarding the San Bruno Accident*

In January 2012, the CPUC commenced an investigation to determine whether the Utility violated applicable laws and requirements in connection with the San Bruno accident, as alleged by the SED. In its January investigative report, the SED alleged that the San Bruno accident was caused by the Utility's failure to follow accepted industry practice when installing the section of pipe that failed, the Utility's failure to comply with federal pipeline integrity management requirements, the Utility's inadequate record keeping practices, deficiencies in the Utility's data collection and reporting system, the Utility's inadequate procedures to handle emergencies and abnormal conditions, the Utility's deficient emergency response actions after the incident, and a systemic failure of the Utility's corporate culture that emphasized profits over safety. The CPUC stated that the scope of the investigation will include all past operations, practices and other events or courses of conduct that could have led to or contributed to the San Bruno accident, as well as, the Utility's compliance with CPUC orders and resolutions issued since the date of the San Bruno accident.

The Utility submitted testimony to the CPUC that acknowledged its liability for the San Bruno accident and, based on testimony from an expert witness, stated that the likely root cause of the pipeline rupture was: (1) a missing interior weld on the pipe; (2) a ductile tear on the pipe likely caused by a hydrostatic test performed in 1956 at too low a pressure to cause the defective weld to fail; and (3) a fatigue crack on the pipe that grew over time. However, the Utility stated that many of the findings identified in the SED's reports are not deficiencies, or are much less severe than alleged, and do not constitute violations of applicable laws and regulations. The CPUC concluded evidentiary hearings in this investigation in January 2013. Briefing on the issue of alleged violations is scheduled to be completed on April 12, 2013.

*Other Potential Enforcement Matters*

California gas corporations are required to provide notice to the CPUC of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The CPUC has authorized the SED to issue citations and impose penalties based on self-reported violations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the SED based on the Utility's self-report that it failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has paid the penalty and completed all of the missed leak surveys.) As of December 31, 2012, the Utility has submitted 34 self-reports with the CPUC, plus additional follow-up reports. The SED has not yet taken formal action with respect to the Utility's other self-reports. The SED may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file. (See "Penalties Conclusion" below.)

In addition, in July 2012, the Utility reported to the CPUC that it had discovered that its access to some pipelines has been limited by vegetation overgrowth or building structures that encroach upon some of the Utility's gas pipeline rights-of-way. The Utility is undertaking a system-wide effort to identify and remove encroachments from its pipeline rights-of-way over a multi-year period. PG&E Corporation and the Utility are uncertain how this matter will affect the above investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced that could result in regulatory orders or the imposition of penalties on the Utility.

*Penalties Conclusion*

The CPUC can impose penalties of up to $20,000 per day, per violation. (For violations that are considered to have occurred on or after January 1, 2012, the statutory penalty has increased to a maximum of $50,000 per day, per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this wide discretion in determining penalties. The CPUC's delegation of enforcement authority to the SED allows the SED to use these factors in exercising discretion to determine the number of violations, but the SED is required to impose the maximum statutory penalty for each separate violation that the SED finds.

The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. In determining the amount of penalties the ALJs may consider the testimony of financial consultants engaged by the SED and the Utility. The SED's financial consultant prepared a report concluding that PG&E Corporation could raise approximately $2.25 billion through equity issuances, in addition to equity PG&E Corporation had already forecasted it would issue in 2012, to fund CPUC-imposed penalties on the Utility. The Utility's financial consultant disagreed with this financial analysis and asserted that a fine in excess of financial analysts' expectations, which the consultant's report cited as a mean of $477 million, would make financing more difficult and expensive. The ALJs have scheduled a hearing to be held on March 4 and March 5, 2013 to consider the SED's and Utility's testimony. The SED and other parties are scheduled to file briefs to address potential monetary penalties and remedies in all three investigations by April 26, 2013.

PG&E Corporation and the Utility believe it is probable that the Utility will incur penalties of at least $200 million in connection with these pending investigations and potential enforcement matters and have accrued this amount in their consolidated financial statements. PG&E Corporation and the Utility are unable to make a better estimate of probable losses or estimate the range of reasonably possible losses in excess of the amount accrued due to the many variables that could affect the final outcome of these matters and the ultimate amount of penalties imposed on the Utility could be materially higher than the amount accrued. These variables include how the CPUC and the SED will exercise their discretion in calculating the amount of penalties, including how the total number of violations will be counted; how the duration of the violations will be determined; whether the amount of penalties in each investigation will be determined separately or in the aggregate; how the financial resources testimony submitted by the SED and the Utility will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and whether and how the financial impact of non-recoverable costs the Utility has already incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered. (See "CPUC Gas Safety Rulemaking Proceeding" below.)

These estimates, and the assumptions on which they are based, are subject to change based on many factors, including rulings, orders, or decisions that may be issued by the ALJs; whether the outcome of the investigations is resolved through a fully litigated process or a stipulated outcome that is approved by the CPUC; whether the SED will take additional action with respect to the Utility's self-reports; and whether the CPUC or the SED takes any action with respect to the encroachment matter described above. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

***CPUC Gas Safety Rulemaking Proceeding***

The CPUC is conducting a rulemaking proceeding to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. On December 20, 2012, the CPUC approved the Utility's proposed pipeline safety enhancement plan (filed in August 2011) to modernize and upgrade its natural gas transmission system but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs the Utility forecasted it would incur over the first phase of the plan (2011 through 2014). The CPUC decision limited the Utility's recovery of capital expenditures to $1.0 billion of the total $1.4 billion requested. Various parties have asked the CPUC to reconsider its decision, arguing that the Utility's cost recovery should be more limited. For 2012, the Utility recorded a $353 million charge to net income for plan-related capital expenditures incurred that are forecasted to exceed the CPUC's authorized levels or that were specifically disallowed. Future disallowed amounts will be charged to net income in the period incurred and could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

***Criminal Investigation***

In June 2011, the Utility was notified that representatives from the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office are conducting an investigation of the San Bruno accident. Federal and state authorities have indicated that the Utility is a target of the investigation. The Utility is cooperating with the investigation. PG&E Corporation and the Utility are uncertain whether any criminal charges will be brought against either company or any of their current or former employees. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Utility as a consequence of this investigation.

***Third-Party Claims***

In addition to the investigations and proceedings discussed above, at December 31, 2012, approximately 140 lawsuits involving third-party claims for personal injury and property damage, including two class action lawsuits, had been filed against PG&E Corporation and the Utility in connection with the San Bruno accident on behalf of approximately 450 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases were coordinated and assigned to one judge in the San Mateo County Superior Court. Many of the plaintiffs' claims have been resolved through settlements. The trial of the first group of remaining cases began on January 2, 2013 with pretrial motions and hearings. On January 14, 2013, the court vacated the trial and all pending hearings due to the significant number of cases that have been settled outside of court. The court has urged the parties to settle the remaining cases. As of February 8, 2013, the Utility has entered into settlement agreements to resolve the claims of approximately 140 plaintiffs. It is uncertain whether or when the Utility will be able to resolve the remaining claims through settlement.

At December 31, 2012, the Utility had recorded cumulative charges of $455 million for estimated third-party claims related to the San Bruno accident, including an $80 million charge made during 2012, primarily to reflect settlements and information exchanged by the parties during the settlement and discovery process. The Utility estimates it is reasonably possible that it may incur as much as an additional $145 million for third-party claims, for a total possible loss of $600 million. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with punitive damages, if any, related to these matters. The Utility has publicly stated that it is liable for the San Bruno accident and will take financial responsibility to compensate all of the victims for the injuries they suffered as a result of the accident.

The following table presents changes in third-party claims activity since the San Bruno accident in 2010; the balance is included in other current liabilities in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| **(in millions)** | |
|---|---|
| Balance at January 1, 2010 | $ - |
| Loss accrued | 220 |
| Less: Payments | (6) |
| Balance at December 31, 2010 | 214 |
| Additional loss accrued | 155 |
| Less: Payments | (92) |
| Balance at December 31, 2011 | 277 |
| Additional loss accrued | 80 |
| Less: Payments | (211) |
| **Balance at December 31, 2012** | **$ 146** |

Additionally, the Utility has liability insurance from various insurers who provide coverage at different policy limits that are triggered in sequential order or "layers." Generally, as the policy limit for a layer is exhausted the next layer of insurance becomes available. The aggregate amount of insurance coverage for third-party liability attributable to the San Bruno accident is approximately $992 million in excess of a $10 million deductible. The Utility has recognized cumulative insurance recoveries for third-party claims of $284 million, which included $185 million for 2012 and $99 million for 2011. Although the Utility believes that a significant portion of costs incurred for third-party claims relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

***Class Action Complaint***

On August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. To state their claims, the plaintiffs cited the SED's January 2012 investigative report of the San Bruno accident that alleged, from 1996 to 2010, the Utility spent less on capital expenditures and operations and maintenance expense for its natural gas transmission operations than it recovered in rates, by $95 million and $39 million, respectively. The SED recommended in that report that the Utility should use such amounts to fund future gas transmission expenditures and operations. Plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of Section 17200 of the California Business and Professions Code ("Section 17200") and claim that this violation also constitutes a violation of California Public Utilities Code Section 2106 ("Section 2106"), which provides a private right of action for violations of the California constitution or state laws by public utilities. Plaintiffs seek restitution and disgorgement under Section 17200 and compensatory and punitive damages under Section 2106.

PG&E Corporation and the Utility contest the plaintiffs' allegations. In January 2013, PG&E Corporation and the Utility requested that the court dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. In the alternative, PG&E Corporation and the Utility requested that the court stay the proceeding until the CPUC investigations described above are concluded. The court has set a hearing on the motion for April 26, 2013. Due to the early stage of this proceeding, PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses that may be incurred in connection with this matter.

***Spent Nuclear Fuel Storage Proceedings***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities. The DOE has been unable to meet its contractual obligation to the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay ("Humboldt Bay Unit 3"). As a result, the Utility constructed an interim dry cask storage facility to store spent fuel at Diablo Canyon through at least 2024, and a separate facility at Humboldt Bay. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

On September 5, 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. As of December 31, 2012, the Utility has collected the settlement proceeds from the U.S. Treasury and recorded the amount as a regulatory balancing account. The proceeds will be refunded to customers through rates in future periods. The agreement also allows the Utility to submit annual claims to re cover costs incurred in 2011, 2012 and 2013, which the Utility estimates to be approximately $25 million per year . These amounts will also be refunded to customers in future periods. At December 31, 2012, PG&E Corporation and the Utility have not recorded any receivables for annual claims in their Consolidated Balance Sheets. The agreement does not address costs incurred for spent fuel storage after 2013 and such costs could be the subject of future litigation. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent nuclear fuel.

***Nuclear Insurance***

The Utility is a member of Nuclear Electric Insurance Limited ("NEIL") which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility due to a nuclear event (meaning that nuclear material is released) that occurs at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident ($2.7 billion for property damage and $490 million for business interruption) for Diablo Canyon. In addition, NEIL provides $131 million of coverage for nuclear and non-nuclear property damages at Humboldt Bay Unit 3. (NEIL also provides insurance coverage to the Utility for non-nuclear property damages and business interruption losses at Diablo Canyon, though with significantly lower limits beginning in April 2013.) Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss, the Utility may be required to pay an additional premium of up to $44 million per one-year policy term. NRC regulations require that the Utility's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant before any proceeds can be used for decommissioning or plant repair.

NEIL policies also provide coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $12.6 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $12.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $235 million per nuclear incident under this program, with payments in each year limited to a maximum of $35 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before October 29, 2013.

The Price-Anderson Act does not apply to public liability claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. Such claims are covered by nuclear liability policies purchased by the enricher and the fuel fabricator, as well as by separate supplier's and transporter's insurance policies. The Utility has a separate supplier's and transporter's policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident.

In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the $53 million of liability insurance.

If the Utility incurs losses in connection with any of its nuclear generation facilities that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

**Environmental Remediation Contingencies**

The Utility has been, and may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The following table presents the changes in the environmental remediation liability:

| **(in millions)** | | |
|---|---|---|
| Balance at December 31, 2011 | $ | 785 |
| Additional remediation costs accrued: | | |
| Transfer to regulatory account for recovery | | 150 |
| Amounts not recoverable from customers | | 150 |
| Less: Payments | | (175) |
| **Balance at December 31, 2012** | **$** | **910** |

The environmental remediation liability is composed of the following:

| | **Balance at December 31,** | | | |
|---|---|---|---|---|
| **(in millions)** | **2012** | | **2011** | |
| Utility-owned natural gas compressor site near Hinkley, California [(1)] | $ | 226 | $ | 149 |
| Utility-owned natural gas compressor site near Topock, Arizona [(1)] | | 239 | | 218 |
| Utility-owned generation facilities (other than for fossil fuel-fired), other facilities, and third-party disposal sites | | 158 | | 133 |
| Former manufatured gas plant sites owned by the Utility or third parties | | 181 | | 154 |
| Fossil fuel-fired generation facilities formerly owned by the Utility | | 87 | | 81 |
| Decommissioning fossil fuel-fired generation facilities and sites | | 19 | | 50 |
| **Total environmental remediation liability** | **$** | **910** | **$** | **785** |

[(1)] See "Natural Gas Compressor Site" below.

The CPUC has authorized the Utility to recover most of its environmental remediation costs through various ratemaking mechanisms, subject to exclusions for certain sites, such as the Hinkley natural gas compressor site, and subject to limitations for certain liabilities such as amounts associated with fossil fuel-fired generation facilities formerly owned by the Utility. At December 31, 2012, the Utility expected to recover $548 million through these ratemaking mechanisms. The Utility also recovers environmental remediation costs from insurance carriers and from other third parties whenever possible. Amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers through rates.

***Natural Gas Compressor Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor sites near Hinkley, California ("Hinkley site") and Topock, Arizona ("Topock site"). The Utility is also required to take measures to abate the effects of the contamination on the environment.

***Hinkley Site***

The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region ("Regional Board"). The Regional Board has issued several orders directing the Utility to implement interim remedial measures to reduce the mass of the underground plume of hexavalent chromium, monitor and control movement of the plume, and provide replacement water to affected residents.

The Utility submitted its proposed final remediation plan to the Regional Board in September 2011 recommending a combination of remedial methods to clean up groundwater contamination, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated the Utility's proposed methods and the potential environmental impacts. The Utility expects that the Regional Board will consider certification of the final EIR in the second quarter of 2013. Upon certification of the EIR, the Regional Board is expected to issue the final cleanup standards in late 2013.

The Regional Board ordered the Utility in October 2011 to provide an interim and permanent replacement water system for resident households located near the chromium plume that have domestic wells containing hexavalent chromium in concentrations greater than 0.02 parts per billion. The Utility filed a petition with the California State Water Resources Control Board to contest certain provisions of the order. In June 2012, the Regional Board issued an amended order to allow the Utility to implement a whole house water replacement program for resident households located near the chromium plume boundary. Eligible residents may decide whether to accept a replacement water supply or have the Utility purchase their properties, or alternatively not participate in the program. As of January 31, 2013, approximately 350 residential households are covered by the program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to complete implementation of the whole house water replacement systems by August 31, 2013. The Utility will maintain and operate the whole house replacement systems for five years or until the State of California has adopted a drinking water standard specifically for hexavalent chromium at which time the program will be evaluated.

At December 31, 2012 and 2011, $226 million and $149 million, respectively, were accrued in PG&E Corporation's and the Utility's Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. The increase primarily reflects the Utility's best estimate of costs associated with the developments described above. Remediation costs for the Hinkley natural gas compressor site are not recovered from customers through rates. Future costs will depend on many factors, including the Regional Board's certification of the final EIR, the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the Utility's required time frame for remediation, and adoption of a final drinking water standard currently under development by the State of California, as mentioned above. As more information becomes known regarding these factors, these estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions may have a material impact on PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows.

***Topock Site***

The Utility's remediation and abatement efforts are subject to the regulatory authority of the Department of Toxic Substances Control ("DTSC") and the U.S. Department of the Interior ("DOI"). As directed by the DTSC, the Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of a hexavalent chromium plume toward the Colorado River. The DTSC has certified the final EIR and approved the Utility's final remediation plan for the groundwater plume, under which the Utility will implement an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has completed the preliminary design stage for implementing the final groundwater remedy and is required to submit its intermediate design plan to the DTSC and DOI by April 5, 2013 and a final plan for approval in 2014. In developing its intermediate plan, the Utility is currently evaluating input received from regulatory agencies and other stakeholders, exploring potential sources of fresh water to be used as part of the remedy, and performing other engineering activities necessary to complete the remedial design.

At December 31, 2012 and 2011, $239 million and $218 million, respectively, were accrued in PG&E Corporation's and the Utility's Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Topock site. The CPUC has authorized the Utility to recover 90% of its remediation costs for the Topock site from customers through rates without a reasonableness review. As the Utility completes its remedial design plan and more information becomes known regarding the extent of work to be performed to implement the final groundwater remedy, these estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to change. Future changes in estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's future financial condition.

***Reasonably Possible Environmental Contingencies***

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.6 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on PG&E Corporation's and the Utility's results of operations during the period in which they are recorded.

## QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

| (in millions, except per share amounts) | Quarter ended December 31 | September 30 | June 30 | March 31 |
|---|---|---|---|---|
| **2012** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 3,830 | $ 3,976 | $ 3,593 | $ 3,641 |
| Operating income | 125 | 614 | 467 | 487 |
| Net income (loss) | (9) | 364 | 239 | 236 |
| Income (loss) available for common shareholders | (13) | 361 | 235 | 233 |
| Net earnings (loss) per common share, basic | (0.03) | 0.84 | 0.56 | 0.56 |
| Net earnings (loss) per common share, diluted | (0.03) | 0.84 | 0.55 | 0.56 |
| Common stock price per share: | | | | |
| High | 43.48 | 46.51 | 45.20 | 43.72 |
| Low | 39.71 | 42.41 | 42.04 | 40.16 |
| **UTILITY** | | | | |
| Operating revenues | $ 3,829 | $ 3,974 | $ 3,592 | $ 3,640 |
| Operating income | 127 | 613 | 467 | 488 |
| Net income | 13 | 340 | 227 | 231 |
| Income available for common stock | 9 | 337 | 223 | 228 |
| | | | | |
| **2011** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 3,815 | $ 3,860 | $ 3,684 | $ 3,597 |
| Operating income | 358 | 408 | 692 | 484 |
| Net income | 87 | 203 | 366 | 202 |
| Income available for common shareholders | 83 | 200 | 362 | 199 |
| Net earnings per common share, basic | 0.20 | 0.50 | 0.91 | 0.50 |
| Net earnings per common share, diluted | 0.20 | 0.50 | 0.91 | 0.50 |
| Common stock price per share: | | | | |
| High | 43.24 | 43.32 | 46.52 | 47.60 |
| Low | 36.86 | 39.21 | 41.39 | 42.47 |
| **UTILITY** | | | | |
| Operating revenues | $ 3,813 | $ 3,859 | $ 3,683 | $ 3,596 |
| Operating income | 359 | 402 | 699 | 484 |
| Net income | 89 | 196 | 359 | 201 |
| Income available for common stock | 85 | 193 | 355 | 198 |

During the fourth quarter 2012, the Utility recorded a charge to net income of $353 million for disallowed capital expenditures associated with the Utility's pipeline safety enhancement plan. See Note 15 of the Notes to the Consolidated Financial Statements.

During the second quarter 2012 the Utility recorded a provision of $80 million for estimated third-party claims related to the San Bruno accident. During the first quarter 2012, second quarter of 2012, third quarter of 2012, and fourth quarter 2012, the Utility submitted insurance claims to certain insurers for the lower layers and recognized $11 million, $25 million, $99 million, and $50 million, respectively, for insurance recoveries. See Note 15 of the Notes to the Consolidated Financial Statements.

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of PG&E Corporation and Pacific Gas and Electric Company ("Utility") is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2012.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the “Utility”) as of December 31, 2012 and 2011, and the Company’s related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility’s related consolidated statements of income, comprehensive income, shareholders’ equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's and the Utility’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 15 to the consolidated financial statements, several investigations and enforcement matters are pending with the California Public Utilities Commission and may result in material amounts of penalties.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility’s internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2013 expressed an unqualified opinion on the Company's and the Utility’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2013

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2012, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and the Utility and our report dated February 21, 2013 expressed an unqualified opinion on those financial statements and includes an explanatory paragraph relating to several investigations and enforcement matters pending with the California Public Utilities Commission that may result in material amounts of penalties.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2013

**Significant Subsidiaries**

| Parent of Significant Subsidiary | Name of Significant Subsidiary | Jurisdiction of Formation of Subsidiary | Names under which Significant Subsidiary does business |
|---|---|---|---|
| PG&E Corporation | Pacific Gas and Electric Company | CA | Pacific Gas and Electric Company<br>PG&E |
| Pacific Gas and Electric Company | None | | |

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-172393 on Form S-3, 333-144498 on Form S-3D, and 333-73054, 333-129422, and 333-176090 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488 and 333-172394 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 21, 2013, relating to the consolidated financial statements (which report expresses an unqualified opinion and includes an explanatory paragraph relating to several investigations and enforcement matters pending with the California Public Utilities Commission that may result in material amounts of penalties), the consolidated financial statement schedules of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility"), and the effectiveness of the Company's and the Utility's internal control over financial reporting, appearing in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2012.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2013

**POWER OF ATTORNEY**

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC A. MONTIZAMBERT, KATHLEEN HAYES, and DOREEN A. LUDEMANN, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2012 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 20th day of February, 2013.

| | |
|---|---|
| | ROGER H. KIMMEL |
| David R. Andrews | Roger H. Kimmel |
| LEWIS CHEW | RICHARD A. MESERVE |
| Lewis Chew | Richard A. Meserve |
| C. LEE COX | FORREST E. MILLER |
| C. Lee Cox | Forrest E. Miller |
| ANTHONY F. EARLEY, JR. | ROSENDO G. PARRA |
| Anthony F. Earley, Jr. | Rosendo G. Parra |
| FRED J. FOWLER | BARBARA L. RAMBO |
| Fred J. Fowler | Barbara L. Rambo |
| MARYELLEN C. HERRINGER | BARRY LAWSON WILLIAMS |
| Maryellen C. Herringer | Barry Lawson Williams |

**POWER OF ATTORNEY**

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC A. MONTIZAMBERT, KATHLEEN HAYES, and DOREEN A. LUDEMANN, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2012 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 20th day of February, 2013.

David R. Andrews

LEWIS CHEW
Lewis Chew

C. LEE COX
C. Lee Cox

ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.

FRED J. FOWLER
Fred J. Fowler

MARYELLEN C. HERRINGER
Maryellen C. Herringer

CHRISTOPHER P. JOHNS
Christopher P. Johns

ROGER H. KIMMEL
Roger H. Kimmel

RICHARD A. MESERVE
Richard A. Meserve

FORREST E. MILLER
Forrest E. Miller

ROSENDO G. PARRA
Rosendo G. Parra

BARBARA L. RAMBO
Barbara L. Rambo

BARRY LAWSON WILLIAMS
Barry Lawson Williams

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2012 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.
Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Kent M. Harvey, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2012 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

KENT M. HARVEY
Kent M. Harvey
Senior Vice President and Chief Financial Officer

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2012 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

CHRISTOPHER P. JOHNS
Christopher P. Johns
President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Dinyar B. Mistry, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2012 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

DINYAR B. MISTRY
Dinyar B. Mistry
Vice President, Chief Financial Officer and Controller

Exhibit 32.1

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2012 ("Form 10-K"), I, Anthony F. Earley, Jr., Chairman, Chief Executive Officer, and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ANTHONY F. EARLEY, JR.

ANTHONY F. EARLEY, JR.
Chairman, Chief Executive Officer, and President

February 21, 2013

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2012 ("Form 10-K"), I, Kent M. Harvey, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

KENT M. HARVEY

KENT M. HARVEY
Senior Vice President and
Chief Financial Officer

February 21, 2013

Exhibit 32.2

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2012 (“Form 10-K”), I, Christopher P. Johns, President of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

CHRISTOPHER P. JONHS

CHRISTOPHER P. JOHNS
President

February 21, 2013

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2012 (“Form 10-K”), I, Dinyar B. Mistry, Vice President, Chief Financial Officer and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

DINYAR B. MISTRY

DINYAR B. MISTRY
Vice President, Chief Financial Officer and Controller

February 21, 2013

# Exhibit 2

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the Fiscal Year Ended December 31, 2013**
**Or**
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from _________ to ___________**

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
77 Beale Street, P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-1000
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company
77 Beale Street, P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| **PG&E Corporation:** Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company:** First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE Amex Equities |

**Securities registered pursuant to Section 12(g) of the Act: None**

**Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:**

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

**Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:**

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.**

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

**Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).**

| | | |
|---|---|---|
| PG&E Corporation | Yes ☑ | No ☐ |
| Pacific Gas and Electric Company | Yes ☑ | No ☐ |

**Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:**

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

**Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):**

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |

**Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).**

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2013, the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $20,326 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |

**Common Stock outstanding as of February 3, 2014:**

| | |
|---|---|
| PG&E Corporation: | 457,663,407 |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

**Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:**

| | |
|---|---|
| Designated portions of the combined 2013 Annual Report to Shareholders | Part I (Items 1, 1A and 3), Part II (Items 5, 6, 7, 7A, 8 and 9A) |
| Designated portions of the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |

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**UNI TS OF MEASUREMENT**

| | | |
|---|---|---|
| 1 Kilowatt (kW) | = | One thousand watts |
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt (GW) | = | One million kilowatts |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |
| 1 Bcf | = | One billion cubic feet |
| 1 MDth | = | One thousand decatherms |

## GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2013 Annual Report | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2013, including the information incorporated by reference into the report |
| AB 32 | California Global Warming Solutions Act of 2006 |
| CAISO | California Independent System Operator |
| CARB | California Air Resources Board |
| CCA | Community choice aggregator |
| CEC | California Energy Commission |
| Central Coast Board | Central Coast Regional Water Quality Control Board |
| CERCLA | Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended |
| CO2 | carbon dioxide |
| CO2-e | CO2-equivalent |
| CPUC | California Public Utilities Commission |
| CSI | California Solar Initiative |
| DOE | U.S. Department of Energy |
| EPA | Environmental Protection Agency |
| ERRA | Energy Resource Recovery Account |
| ESC | Engineers and Scientists of California |
| Exchange Act | Securities Exchange Act of 1934, as amended |
| FERC | Federal Energy Regulatory Commission |
| GHG | greenhouse gas |
| GRC | general rate case |
| GTN | Gas Transmission Northwest Corporation |
| GT&S | gas transmission and storage |
| IBEW | International Brotherhood of Electrical Workers |
| LTIP | PG&E Corporation long-term incentive plan |
| MD&A | Management’s Discussion and Analysis of Financial Condition and Results of Operations |
| MGP | manufactured gas plant |
| NERC | North American Electric Reliability Corporation |
| NOx | nitrogen oxide |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| ORA | Office of Ratepayer Advocates |
| OSC | CPUC Order to Show Cause |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PSEP | pipeline safety enhancement plan |
| PV | photovoltaic |
| QF(s) | qualified facilities |
| ROE | return on equity |
| RPS | renewable portfolio standard |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD |
| SEIU | Service Employees International Union, United Service Workers West |
| SO2 | sulfur dioxide |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| WECC | Western Interconnection to the Western Electricity Coordinating Council |

PART I

***ITEM 1. Bus iness***

**General**

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. The Utility's revenues are generated mainly through the sale and delivery of electricity and natural gas to customers.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000. PG&E Corporation and the Utility file or furnish various reports with the SEC. These reports, including Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Exchange Act, are available free of charge on both PG&E Corporation's website, www.pgecorp.com , and the Utility's website, www.pge.com , as promptly as practicable after they are filed with, or furnished to, the SEC. The information contained on these websites is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report.

This is a combined Annual Report on Form 10-K of PG&E Corporation and the Utility and includes information incorporated by reference from the joint Annual Report to Shareholders for the year ended December 31, 2013, which is attached to this report as Exhibit 13 and the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders. The 2013 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the information in the 2013 Annual Report under the headings "Cautionary Language Regarding Forward-Looking Statements" and "Risk Factors" which appear under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations."

***Natural Gas Operations***

During 2013, the Utility continued to make significant progress on efforts to improve the safety and reliability of its natural gas operations, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's PSEP, approved by the CPUC in December 2012, to modernize and upgrade its natural gas transmission system to meet new, industry-wide safety standards. In July 2013, the Utility completed its search and review of records relating to pipeline pressure validation for all approximately 6,750 miles of its natural gas transmission system. Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011 following their investigations into the rupture of one of the Utility's natural gas transmission pipelines in San Bruno, California on September 9, 2010 (the "San Bruno accident"). (For more information, see "Natural Gas Utility Operations" below.)

During 2013, the Utility settled the majority of the civil lawsuits that were filed after the San Bruno accident. The CPUC investigations and the criminal investigation that were commenced after the San Bruno accident are still unresolved. The CPUC's SED also may take enforcement action with respect to numerous reports the Utility has filed to report noncompliance with various natural gas regulations. See information under the headings within MD&A entitled "Natural Gas Matters" and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report which information is incorporated herein by reference.

***Electricity Operations***

During 2013, the Utility made significant capital investments to improve and modernize its electricity operations by repairing, replacing, or upgrading equipment to improve safety and reliability. The Utility has substantially completed the installation of advanced electric and gas meters throughout its service territory and continued taking steps to lay the foundation for the development of a "smart grid" to enable customers to have better control over their energy usage and costs, to integrate new sources of energy, and to enable the continued safe and reliable operation of the grid. In 2013, the Utility received regulatory approval to pilot and test new "smart grid" technologies that have the potential to support the provision of safe, reliable and affordable electric service. (For more information, see "Electric Utility Operations" below.)

***Employees***

At December 31, 2013, PG&E Corporation and its subsidiaries had 21,166 regular employees, including 21,159 regular employees of the Utility. Of the Utility's regular employees, 13,150 are covered by collective bargaining agreements with three labor unions: the IBEW; the ESC; and the SEIU. There are two collective bargaining agreements with IBEW. Both bargaining agreements expire on December 31, 2014. The ESC collective bargaining agreement also expires on December 31, 2014. The SEIU collective bargaining agreement expires on July 31, 2015.

**Regu latory Environment**

The Utility's business is subject to a complex set of energy, environmental and other laws, regulations, and regulatory proceedings at the federal, state, and local levels. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. For discussion of specific pending regulatory matters that are expected to affect the Utility, see the information under the headings within MD&A entitled "Regulatory Matters" and "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.

PG&E Corporation is a "public utility holding company" as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight of the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

***Federal Regulation***

*The Federal Energy Regulatory Commission*

The FERC regulates the transmission of electricity and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. The FERC also regulates interconnections of transmission systems with other electric systems and generation facilities, tariffs and conditions of service of regional transmission organizations, including the CAISO, and the terms and rates of wholesale electricity sales. The FERC has authority to impose fines of up to $1 million per day for violation of certain federal statutes and regulations. The FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas.

The FERC has the responsibility to approve and enforce mandatory standards governing the reliability of the nation's electricity transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches, to prevent market manipulation, and to supplement state transmission siting efforts in certain electric transmission corridors that are determined to be of national interest. The FERC certified the NERC as the nation's Electric Reliability Organization. The NERC is responsible for developing and enforcing electric reliability standards, subject to FERC approval. The FERC also has approved a delegation agreement under which the NERC has delegated enforcement authority for the geographic area known as the Western Interconnection to the Western Electricity Coordinating Council. The Utility must self-certify compliance to the WECC on an annual basis and the compliance program encourages self-reporting of violations. WECC staff, with participation by the NERC and the FERC, also performs a compliance audit of the Utility every three years. The FERC also has authorized the WECC and the NERC to impose fines up to $1 million per day, per violation.

The FERC also has adopted policies and rules to promote investment in energy infrastructure and lower costs for consumers through incentive ratemaking for transmission projects. In addition, the FERC's Order No. 1000 establishes electric transmission planning and cost allocation requirements for public utility transmission providers. Order No. 1000 requires public utility transmission providers to improve transmission planning processes and allocate costs for new transmission facilities to the beneficiaries of those facilities.

The CAISO is responsible for providing open access electricity transmission service on a non-discriminatory basis, planning transmission system additions, and ensuring the maintenance of adequate reserves of generation capacity.

***The Nuclear Regulatory Commission***

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and additional significant capital expenditures could be required in the future. For information about NRC matters affecting Diablo Canyon, including the status of the Utility's relicensing application see the information under the heading within MD&A entitled "Regulatory Matters−Diablo Canyon Nuclear Power Plant" in the 2013 Annual Report, which information is incorporated herein by reference.

***The Pipeline and Hazardous Materials Safety Administration***

The Utility also is subject to regulations adopted by the federal PHMSA that is within the United States Department of Transportation. The PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's pipeline transportation system and the shipment of hazardous materials. The PHMSA also has authorized the CPUC to enforce the federal pipeline safety standards over intrastate natural gas pipelines, as well as any state pipeline safety requirements that do not conflict with the federal requirements, through fines and/or injunctive relief.

***The National Transportation Safety Board***

The NTSB is an independent federal agency that is authorized to investigate pipeline accidents and certain transportation accidents that involve fatalities, substantial property damage, or significant environmental damage. The NTSB investigated the San Bruno accident and in August 2011 announced that it had determined the probable cause of the San Bruno accident placing the blame primarily on the Utility. The NTSB report recommended that the Utility take certain actions to improve the safety of its gas transmission system. The status of the Utility's implementation of the NTSB's recommendations is discussed under "Natural Gas Utility Operations" below.

***State Regulation***

*The California Public Utilities Commission*

The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electricity generation, and natural gas transportation and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas gathering, transmission, and distribution pipeline systems, and for the safe operation of such pipelines and equipment. The CPUC has adopted many rules and regulations to implement state laws and policies, such as the laws relating to the development of renewable energy resources, demand response and public purpose programs, reduction of GHG emissions, and development of energy storage capacity. As discussed above, the CPUC also has been delegated authority to enforce compliance with certain federal regulations related to the safety of natural gas facilities. The CPUC has authority to impose fines for violating these state and federal laws, orders, or regulations of up to $50,000 per violation, per day. (See the discussion under the heading within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report for information about the CPUC's pending enforcement proceedings against the Utility relating to the Utility's gas operations, which discussion is incorporated herein by reference.)

In addition, California law enacted in 2013 requires the CPUC to develop a safety enforcement program that authorizes CPUC staff to issue citations for safety violations and assess fines subject to a CPUC-approved limit. The CPUC is required to implement the safety enforcement program for gas corporations by July 1, 2014 and for electric corporations by January 1, 2015. (See the discussion under the heading within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report for information about the reports the Utility has filed to notify the CPUC staff of noncompliance with certain gas safety regulations.)

Ratemaking for retail sales from the Utility's generation facilities is under the jurisdiction of the CPUC. To the extent that this electricity is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. In addition, the CPUC has general jurisdiction over most of the Utility’s operations, and regularly reviews the Utility’s performance, using measures such as the frequency and duration of outages. The CPUC also conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies.

The CPUC has imposed conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates. These conditions relate to finance, human resources, records and bookkeeping, and the transfer of customer information. Among other conditions, the financial conditions provide that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, must be given first priority by PG&E Corporation’s Board of Directors (known as the “first priority” condition). In addition, the Utility must maintain on average its CPUC-authorized utility capital structure, although it can request a waiver of this condition if an adverse financial event reduces the Utility’s common equity component by 1% or more. The CPUC also has adopted rules governing transactions between California's CPUC-regulated electricity and gas utilities and certain of their affiliates that are not regulated by the CPUC primarily to prevent these affiliates from gaining an unfair advantage over their unaffiliated competitors.

*The California Energy Resources Conservation and Development Commission*

The California Energy Resources Conservation and Development Commission, commonly called the CEC, is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW, overseeing funding programs that support public interest energy research, advancing energy science and technology through research, development and demonstration, and providing market support to existing, new, and emerging renewable technologies. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

*The California Air Resources Board*

The CARB is the state agency charged with setting and monitoring GHG and other emission limits. The CARB also is responsible for adopting and enforcing regulations to meet the AB 32, which requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2013. (For more information, see “Environmental Matters — Air Quality and Climate Change” below.)

***Other Regulation***

The Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. These permits include discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation facility and transmission line licenses, and NRC licenses. (For more information, see “Environmental Matters — Water Quality” below.)

The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties. In most cases, the Utility’s franchise agreements are for an indeterminate term, with no expiration date. The Utility has several franchise agreements that have a specified term of years, including an agreement with a large charter city.

The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations.

***Competition in the Electricity Industry***

At the federal level, the FERC is charged with developing rules to encourage fair and efficient competitive wholesale electric markets by employing best practices in market rules and reducing barriers to trade between markets and among regions. (See “Regulatory Environment−Federal Regulation” above for a description of some of these rules.) The FERC also has authority to prevent accumulation and exercise of market power by assuring that proposed mergers and acquisitions of public utility companies and their holding companies are in the public interest and by addressing market power in jurisdictional wholesale markets through its new powers to establish and enforce rules prohibiting market manipulation. The FERC also has issued rules on the interconnection of generators to require regulated transmission providers, such as the Utility or the CAISO, to use standard interconnection procedures and a standard agreement for generator interconnections. These rules are intended to limit opportunities for electric transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage investment in generation and transmission.

In 1998, California became one of the first states to (1) allow customers of the California investor-owned electric utilities to purchase electricity from energy service providers other than the regulated utilities (referred to as "direct access") and (2) establish a competitive market for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity. The wholesale electricity market failed to function as anticipated leading to the 2000-2001 California energy crisis, the suspension of direct access, and the Utility's reorganization under Chapter 11 of the U.S. Bankruptcy Code. (For information about the unresolved disputed claims made by power suppliers in the Utility's Chapter 11 proceeding, see Note 12: Resolution of Remaining Chapter 11 Disputed Claims, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.)

Current California law allows for the gradual phase-in of direct access subject to annual and overall limits (measured in GWh) that have been specified for each utility based roughly on each utility's highest level of direct access before the CPUC suspended direct access. A four-year phase-in period began in April 2010 to allow qualifying non-residential customers of the three California investor-owned electric utilities to purchase electricity from alternate service providers, subject to the limits. The Utility's maximum, 9,520 GWh, was reached in November 2013. Although the Utility's total amount of direct access load may increase due to natural load growth for existing direct access customers, further legislative action is required before new customers can be enrolled in excess of these limits.

In addition, the Utility's customers may, under certain circumstances, obtain power from a CCA instead of from the Utility. California law permits cities and counties and certain other public agencies to purchase and sell electricity for their local residents and businesses after they have registered as CCAs. Under these arrangements, the Utility continues to provide distribution, metering, and billing services to the customers of the CCAs and remains the electricity provider of last resort for those customers. The law provides that a CCA can procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. Under the CPUC's rules, a surcharge is imposed on retail end-users of the CCA to prevent a shifting of costs to customers who continue to receive electricity from a utility. The law also authorizes the Utility to recover from each CCA any costs of implementing the program that are reasonably attributable to the CCA, and to recover from all customers any costs of implementing the program not reasonably attributable to a CCA. Approximately 125,000 customers are now receiving commodity service from the Marin Energy Authority, a CCA. Sonoma Clean Power, another CCA, is expected to begin service to a subset of customers in Sonoma County in May 2014.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, seek to acquire the Utility's distribution facilities. For example, South San Joaquin Irrigation District has indicated that, if it receives the requested authority to provide electric distribution service in and around certain cities (Manteca, Ripon, and Escalon), it will seek to acquire the Utility's distribution facilities, either under a consensual transaction, or via eminent domain.

It is also possible that technological developments could pose challenges for traditional utilities. In particular, technology-related cost declines and sustained federal or state subsidies could make the combination of "distributed generation" and storage a viable, cost-effective alternative to the Utility's bundled electric service. In addition, the levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits at the full retail rate, are increasing.

Although the CPUC has established ratemaking mechanisms that allow the Utility to collect some non-bypassable or fixed charges from those who procure electricity from alternate sources, rates for the Utility's remaining customers could increase as alternative energy providers (CCAs or local government agencies) and alternative energy sources (self-generation and storage, distributed generation, electric vehicles) become more prevalent. Increasing rate pressure on remaining customers could, in turn, cause more customers to seek alternative energy providers or sources, further exacerbating the Utility's rate challenges. New state legislation that became effective on January 1, 2014 (Assembly Bill 327) gave the CPUC new authority to reduce the cost shift associated with customers installing renewable distributed generation under the net energy metering rules.

In addition, the Utility competes with third parties to make various capital investments such as new utility-owned generation facilities, electric transmission projects, SmartGrid electric reliability projects, and distributed generation technologies. The Utility generally participates through a competitive requests-for-offers process that is subject to the oversight of the CPUC or the FERC. If the Utility is selected as the winning bidder, the Utility submits the executed contract for regulatory approval and cost recovery authorization.

***Competition in the Natural Gas Industry***

Under the FERC's rules, interstate natural gas pipeline companies are required to divide their services into separate gas commodity sales, transportation, and storage services and must provide transportation service whether or not the customer (often a local gas distribution company) buys the natural gas from these companies. The Utility's natural gas pipelines are located within the State of California and are exempt from most of the FERC's rules and regulations applicable to interstate pipelines; the Utility's pipeline operations are instead subject to the jurisdiction of the CPUC.

The Utility's gas transmission and storage system has operated under the CPUC-approved "Gas Accord" market structure since 1998 which largely mimics the regulatory framework required by the FERC for interstate gas pipelines. (See "Ratemaking Mechanisms" below.) The CPUC divides the Utility's natural gas customers into two categories: "core" customers, who are primarily small commercial and residential customers, and "non-core" customers, who are primarily industrial, large commercial, and electric generation customers. Although most of the Utility's core customers purchase natural gas directly from the Utility (along with transportation and distribution services as bundled services), core customers have the option to purchase natural gas from independent, unregulated natural gas marketers. Most of the Utility's noncore customers make natural gas supply arrangements directly with producers or purchase natural gas from marketers.

Non-core customers have access to capacity rights for firm service on the Utility's natural gas pipeline, as well as interruptible (or "as-available") services. All services are offered on a nondiscriminatory basis to any creditworthy customer. This market structure has resulted in a robust wholesale gas commodity market at the Utility's "Citygate," which refers to the non-physical interconnection between the big "backbone" gas transmission system and the smaller downstream local transmission systems.

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California, relative to the total delivered cost of natural gas from the southwestern United States. In general, when the total cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California increases relative to other competing natural gas sources, the Utility's market share of transportation services into southern California decreases. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

In addition, the Utility competes with third parties to make various capital investments – such as new natural gas storage facilities. The Utility generally participates through a competitive requests-for-offers process that is subject to the oversight of the CPUC or the FERC. If the Utility is selected as the winning bidder, the Utility submits the executed contract for regulatory approval and cost recovery authorization.

**Ra temaking Mechanisms**

The Utility's rates for electricity and natural gas utility services are based on its costs of providing service ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs (depreciation, tax, and financing expenses) of providing utility services. The Utility's revenue requirements are set based on forecasted costs. Differences in the amount or timing between forecast costs and actual costs could negatively affect the Utility's ability to earn its authorized return.

To develop retail rates, the revenue requirements are allocated among customer classes which are mainly residential, commercial, industrial, and agricultural. Rate changes become effective prospectively on or after the date of CPUC or FERC decisions. Most rate changes approved by the CPUC throughout the year are consolidated to take effect on the first day of the following year.

California Assembly Bill 327, effective on January 1, 2014, repealed prior law that restricted the CPUC's ability to change residential electric rates and to reduce the level of rate assistance for certain low-income customers. AB 327 also authorized the CPUC to approve fixed charges to be collected from residential customers. The CPUC has ordered the California investor-owned utilities, including the Utility, to file proposals for changing residential rates that are consistent with the new law. The current procedural schedule calls for a final decision in the first half of 2014 to approve changes to the Utility's residential electric rates for summer 2014, and a final decision by year-end 2014 to approve broader changes in residential electric rates.

While the CPUC generally uses cost-of-service ratemaking to develop revenue requirements and rates, it selectively uses incentive ratemaking, which bases rates on the extent to which the utilities meet objective or fixed standards or goals, such as energy efficiency goals, instead of on the cost of providing service. See "Public Purpose and Customer Programs" below.

***Electricity and Natural Gas Distribution and Electricity Generation Operations***

*General Rate Cases*

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs related to its electricity and natural gas distribution and electricity generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The CPUC generally conducts a GRC every three years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases (known as "attrition adjustments") in revenue requirements for the subsequent years of the GRC period. Attrition rate adjustments are provided to avoid a reduction in earnings due to, among other things, inflation and increases in invested capital. Intervenors in the Utility's GRC include the CPUC's ORA and TURN, who generally represent the overall interests of customers, as well as a myriad of other intervenors who represent more limited interests.

In November 2012, the Utility filed its 2014 GRC application with the CPUC for rates effective from 2014 through 2016. The CPUC has concluded evidentiary hearings and briefing in the 2014 GRC and the Utility is now waiting for the CPUC to issue a proposed decision. For more information see the heading within MD&A entitled "Regulatory Matters – 2014 General Rate Case" in the 2013 Annual Report, which information is incorporated herein by reference.

In November 2013, the CPUC opened a proceeding to consider modifications to the processing and content of GRCs (and for the Utility's GT&S rate cases) to better integrate and prioritize safety, reliability, and security issues by developing a risk-based decision-making framework for the CPUC to use in evaluating the utilities' requested revenue requirements. The CPUC also will consider whether to change the current three-year rate case cycle and whether to retain the requirement that the ORA review a draft of the utilities' GRC applications prior to filing. A decision is expected to be issued in late 2014.

*Cost of Capital Proceedings*

The CPUC authorizes the Utility's capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) and the authorized rates of return on each component that the Utility may earn on its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2015, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also authorized the Utility to earn a ROE of 10.40% effective January 1, 2013, compared to the 11.35% previously authorized. The Utility's ROE can be automatically adjusted if the 12-month October-through-September average of the Moody's Investors Service long-term Baa utility bond index increases or decreases by more than 1.00% as compared to the applicable benchmark. If the adjustment mechanism is triggered, the Utility's authorized ROE, beginning January 1 of the following year, would be adjusted by one-half of the difference between the index and the benchmark. Additionally, the Utility's authorized costs of long-term debt and preferred stock would be updated to reflect actual August month-end embedded costs and forecasted interest rates for variable long-term debt, as well as new long-term debt and preferred stock scheduled to be issued. In any year where the 12-month average yield triggers an automatic ROE adjustment, that average would become the new benchmark.

The Utility will file its next full cost of capital application in April 2015 for the 2016 test year.

***Rate Recovery of Costs of Electricity Generation Resources***

California investor-owned electric utilities are required to use the principles of “least-cost dispatch” in managing electric generation resources to meet customer demand for electricity. The utilities are also responsible for procuring electricity required to meet customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electricity contracts. To accomplish this, each utility must submit a ten-year procurement plan to the CPUC for approval. Each procurement plan must be designed to use the State of California’s preferred loading order to meet the forecasted demand (i.e., increases in future demand will be offset through energy efficiency programs, demand response programs, renewable generation resources, distributed generation resources, and new conventional generation). The CPUC approved the Utility’s electricity procurement plan in January 2012 covering 2011 through 2020 and approved the Utility’s GHG compliance instrument procurement plan in April 2012.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved electricity procurement plans without further after-the-fact reasonableness review. To the extent the Utility’s electricity purchases are not in compliance with the CPUC-approved plan, costs associated with those purchases may be disallowed. The Utility recovers its electricity procurement costs through the ERRA, a balancing account authorized by the CPUC, that tracks the difference between (1) billed and unbilled ERRA revenues and (2) electric procurement costs incurred under the Utility's authorized procurement plans. Each year, to determine the rates used to collect ERRA revenues, the CPUC reviews the Utility’s forecasted procurement costs related to power purchase agreements, hedging, and generation fuel expense and approves a forecasted revenue requirement.

On December 19, 2013, the CPUC approved the Utility’s forecast of 2014 procurement costs and associated revenue requirement. Changes in rates to reflect the approved revenue requirement became effective on January 1, 2014. (The CPUC may adjust a utility’s retail electricity rates at any time when the forecasted aggregate over-collections or under-collections in the ERRA exceed five percent of its prior year electricity procurement revenues.) The CPUC also performs an annual compliance review to ensure that (1) the Utility prudently administered the contracts that were entered into in accordance with its CPUC-approved procurement plans, (2) utilized the principles of least-cost dispatch in managing its electric generation resources, and (3) prudently operated its own generation facilities.

*Costs Incurred Under New Power Purchase Agreements*

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility’s CPUC-approved procurement plan, the renewable energy mandate, and resource adequacy requirements and has authorized the Utility to recover costs associated with these contracts through the ERRA.

For new non-renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through either (1) a non-bypassable customer charge or (2) the allocation of the “net capacity costs” (i.e., contract price less energy revenues) to all “benefiting customers” in the Utility’s service territory, including direct access customers and CCA customers under certain circumstances. The non-bypassable charge can be imposed from the date of signing a power purchase agreement and can last for ten years from the date the new generation unit comes on line or for the term of the contract, whichever is less. Utilities are allowed to justify a cost recovery period longer than ten years on a case-by-case basis. If a utility uses the net capacity cost allocation method, the net capacity costs are allocated for the term of the contract. To use the net capacity allocation method, the CPUC must determine that a resource was needed to meet system or local area reliability needs for the benefit of all distribution customers. The CPUC can decide whether to require an energy auction for resources subject to the net capacity cost allocation.

For renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through the imposition of a non-bypassable charge on customers.

*Costs of Utility-Owned Generation Resource Projects*

The Utility's recovery of its capital costs and non-fuel operating and maintenance costs for Utility-owned generation facilities is addressed in the Utility's GRC. From time to time, the Utility may also request the CPUC to authorize additional revenue requirements to recover capital investments and operating costs associated with new Utility-owned generation facilities in a separate ratemaking proceeding. The Utility may recover any above-market costs associated with new utility-owned generation resources in a manner similar to the recovery of above-market costs for non-renewable generation purchases described above. The recovery of above-market costs is typically addressed in the CPUC order approving a specific utility-owned generation project.

***Electricity Transmission***

The Utility's electricity transmission revenue requirements and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two main sources of transmission revenues: (1) charges under the Utility's TO tariff and (2) charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in 1998. These wholesale customers are referred to as existing transmission contract customers and are charged individualized rates based on the terms of their contracts. Other customers pay transmission rates that are established by the FERC in the Utility's TO tariff rate cases. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and are collected from retail electric customers receiving bundled service.

*TO Rate Cases*

The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility is authorized to recover for its electric transmission costs and to earn its return on equity is the TO rate case. The Utility generally files a TO rate case every year. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. See the information within MD&A entitled "Electric Transmission Owner Rate Cases" in the 2013 Annual Report, which information is incorporated herein by reference.

The Utility's TO tariff includes several rate components. The primary component consists of base transmission rates intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense, and return on equity. The Utility derives the majority of the Utility's transmission revenue from base transmission rates. Another component consists of rates that reflect credits and charges from the CAISO for transmission revenues received by the CAISO for providing wholesale wheeling service (i.e., the transfer of electricity that is being sold in the wholesale market) to third parties using the Utility's transmission facilities and charges related to the cost of providing service to existing transmission contract customers under specific contracts. The CAISO also imposes a transmission access charge on the Utility for use of the CAISO-controlled electric transmission grid in serving its customers, which are recovered from the Utility's retail customers as part of transmission rates.

***Natural Gas Transmission***

*Costs Incurred Under the Pipeline Safety Enhancement Plan*

Following the San Bruno accident, the CPUC began a rulemaking proceeding in 2011 to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. As part of this proceeding, the CPUC ordered the California natural gas utilities to submit proposed plans to modernize and upgrade their natural gas transmission systems, including cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP but disallowed the Utility's request for rate recovery of a significant portion of PSEP-related costs that the Utility forecasted it would incur through 2014. The CPUC authorized the Utility to recover costs, subject to the adopted capital and expense amounts, for activities including pipeline strength testing, pipeline replacement, in-line inspection, and the installation of automated valves. The CPUC prohibited the Utility from recovering the costs of pressure testing pipeline placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC ordered the Utility to file an update PSEP application after the Utility completes its search and review of records relating to pipeline pressure validation for all 6,750 miles of the Utility's natural gas transmission pipelines. On October 29, 2013, the Utility submitted its update application to present the results of its completed records search and review and to request approval of adjusted revenue requirements for 2014. Based on the information obtained through the records search and review, the Utility has proposed to change the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects. See the information under the headings within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in a separate rate case called the GT&S rate case. The CPUC's decision in the most recent GT&S rate case approved a settlement agreement, known as the Gas Accord V, which set the Utility's rates and associated revenue requirements for natural gas transmission and storage services from January 1, 2011 through December 31, 2014. In December 2013, the Utility filed its 2015 GT&S rate case application with the CPUC covering 2015 through 2017. The Utility's forecasts for the 2015 GT&S rate case period are consistent with state law, which requires gas corporations to develop a plan to identify and minimize hazards and systemic risk for public and employee safety. The forecasts include the continuation of work begun in the Utility's PSEP, such as testing pipelines to verify safe operating pressures, replacing older pipelines, installing more valves, and inspecting the interior of more pipelines. The Utility forecasts that it will incur certain costs that it will not seek to recover from customers. See the information under the heading within MD&A entitled "2015 Gas Transmission and Storage Rate Case" in the 2013 Annual Report, which information is incorporated herein by reference.

Under the current ratemaking mechanisms (which have been in existence since 1998 when the first Gas Accord settlement agreement became effective), the Utility's ability to recover a portion of its revenue requirements depends on throughput volumes, gas prices, and the extent to which large industrial customers, large commercial customers, and other shippers contract for firm transmission services. In its 2015 GT&S rate case application, the Utility has proposed eliminating these current mechanisms and that the CPUC establish new two-way balancing accounts to allow the Utility to record differences between actual customer billings and the Utility's authorized revenue requirements for natural gas transmission and storage revenues. Any over-collections would be returned to customers and any under-collections would be paid by customers.

Under the current ratemaking mechanisms, revenue requirements allocated to core customers are decoupled and recovered through balancing accounts that ensure the Utility recovers only its adopted amounts, no more or less. Revenue requirements allocated to non-core customers are subject to a sharing mechanism. Annually, differences between the authorized revenue requirements and actual customer billings are shared between customers and the Utility's shareholders to varying degrees, depending on the type of service. The Utility is currently at risk for approximately 25% of its total authorized GT&S revenue requirements. In its 2015 GT&S rate case application, the Utility has proposed to discontinue the sharing mechanism and to, instead, recover its non-core revenue requirements in the same decoupled manner as its core revenue requirements though existing balancing accounts. Non-core customers are typically large commercial, industrial, electric generation or wholesale customers who meet required usage requirements. These customers must obtain their own gas procurement and are subject to curtailment.

*Biennial Cost Allocation Proceeding*

Certain of the Utility's natural gas distribution costs and balancing account balances are allocated to customers in the CPUC's Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any over-collection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

*Natural Gas Procurement*

The Utility recovers the cost of gas purchased on behalf of core customers, as well as some core hedging costs, through its retail gas rates subject to a limited incentive mechanism based on a market-priced benchmark. The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered through retail electricity rates. (For more information, see Note 9: Derivatives, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference).

*Interstate and Canadian Natural Gas Transportation*

The Utility has a number of agreements with interstate and Canadian third-party transportation service providers to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These are governed by tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, and the applicable Canadian tariffs are approved by the Alberta Utilities Commission and the National Energy Board. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as electricity procurement costs. For more information, see the discussion below under "Natural Gas Utility Operations — Interstate and Canadian Natural Gas Transportation Services Agreements" below.

**Electr ic Utility Operations**

During 2013, the Utility made significant capital investments to modernize and upgrade its electric transmission and distribution infrastructure to extend the life of or replace existing infrastructure; to maintain and improve system reliability, safety, and customer service; to integrate more renewable energy resources; to increase capacity; and add new infrastructure to meet customer demand growth. The Utility improved the reliability of its system by adding emergency capacity at substations, increasing distribution system automation, upgrading poor performing circuits, performing targeted asset replacement, and improving service outage restoration processes. The Utility also has been working to accelerate pole replacement and maintenance of its overhead and underground electric facilities and to increase the use of wireless devices that allow the Utility to monitor the performance of the electric system and respond more quickly to power disruptions.

The Utility's advanced metering infrastructure supports the development of a "smart grid" in California, part of a nationwide effort to improve and modernize the nation's electric system by combining advanced communications and controls to create a responsive and resilient energy delivery network. The Utility has substantially completed the installation of an advanced metering infrastructure throughout its service territory in 2012. (As permitted by CPUC rules, customers may choose not to have an advanced meter installed.) The new infrastructure uses SmartMeter ™ technology that can measure energy use in hourly or quarter-hourly increments, allow customers to track energy usage throughout the billing month and thus enable greater customer control over electricity costs. Usage data is collected through a wireless communications network and transmitted to

the Utility's information system where the data is stored and used for billing and other Utility business purposes.

The Utility is also incorporating the latest "smart grid" technology in parts of its service territory by installing automated switches that reduce outage duration and the number of customers affected by outages. The Utility also received regulatory approval to pilot and test new "smart grid" technologies that have the potential to support the provision of safe, reliable and affordable electric service. Over the next several years, the Utility plans to undertake various "smart grid" projects and invest in "smart grid" technologies.

***Electricity Resources***

The Utility is required to maintain physical generating capacity adequate to meet its customers' load, including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio in the most cost-effective way. The following table shows the percentage of the Utility's total actual deliveries of electricity to customers in 2013 represented by each major electricity resource, and further discussed below.

Total 2013 Actual Electricity Delivered – 75,705 GWh:

| | Percent of Bundled Retail Sales | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 23.8% | |
| Small Hydroelectric | 1.2% | |
| Large Hydroelectric | 9.4% | |
| Fossil fuel-fired | 8.1% | |
| Solar | 0.4% | |
| Total | | 42.9% |
| Qualifying Facilities | | |
| Renewable | 4.1% | |
| Non-Renewable | 8.9% | |
| Total | | 13.0% |
| Irrigation Districts and Water Agencies | | |
| Small Hydroelectric | 0.2% | |
| Large Hydroelectric | 1.9% | |
| Total | | 2.1% |
| Other Third-Party Purchase Agreements | | |
| Renewable | 16.6% | |
| Large Hydroelectric | 0.6% | |
| Non-Renewable | 13.0% | |
| Total | | 30.2% |
| Others, Net [1] | | 11.8% |
| **Total** | | 100% |

[1] Mainly comprised of net CAISO open market purchases, offset by transmission and distribution related system losses.

*Owned Generation Facilities*

At December 31, 2013, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---|---|---|---|
| Nuclear: | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric: | | | |
| Conventional | 16 counties in northern and central California | 104 | 2,670 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Hydroelectric subtotal: | | 107 | 3,882 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| CSU East Bay Fuel Cell | Alameda | 1 | 1.4 |
| SF State Fuel Cell | San Francisco | 2 | 1.6 |
| Fossil fuel-fired subtotal: | | 15 | 1,403 |
| Photovoltaic: | Various | 13 | 152 |
| **Total** | | 137 | 7,677 |

*Diablo Canyon Power Plant.* The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the year ended December 31, 2013, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 92%. The NRC operating license for Unit 1 expires in November 2024, and the NRC operating license for Unit 2 expires in August 2025. For more information on matters affecting Diablo Canyon, see the section of MD&A entitled "Regulatory Matters–Diablo Canyon Nuclear Power Plant" in the 2013 Annual

Report, which information is incorporated herein by reference. The ability of the Utility to produce nuclear generation depends on the availability of nuclear fuel. The Utility has entered into various purchase agreements for nuclear fuel that are intended to ensure long-term fuel supply. For more information about these agreements, see Note 14: Commitments and Contingencies — Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

The following table outlines the Diablo Canyon power plant's refueling schedule for the next five years. The Diablo Canyon power plant refueling outages are typically scheduled every 20 months. The average length of a refueling outage over the last five years has been approximately 49.5 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

| | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|
| Unit 1 | | | | | |
| Refueling | February | September | - | April | - |
| Startup | March | November | - | May | - |
| Unit 2 | | | | | |
| Refueling | October | - | May | - | February |
| Startup | November | - | June | - | March |

*Hydroelectric Generation Facilities.* The Utility's hydroelectric system consists of 107 generating units at 67 powerhouses, including the Helms pumped storage facility. Most of the Utility's hydroelectric generation units are classified as "large" hydro facilities, as their powerhouse capacity exceeds 30 MW. The system includes 98 reservoirs, 73 diversions, 169 dams, 173 miles of canals, 43 miles of flumes, 132 miles of tunnels, 65 miles of pipe (penstocks, siphons and low head pipes), and 4 miles of natural waterways, and approximately 140,000 acres of fee-owned land. The system also includes water rights as specified in 89 permits or licenses and 160 statements of water diversion and use. The Helms pumped storage facility consists of three motor/generator units.

All of the Utility's powerhouses are licensed by the FERC (except for three small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years. The Utility is in the process of renewing hydroelectric licenses associated with capacity of approximately 1,138 MW and surrendering the hydroelectric license associated with the Kilarc-Cow Creek Project which has a capacity of 5 MW. Although the original licenses associated with 1,070 MW of the 1,138 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 2,812 MW of hydroelectric power will expire between 2014 and 2047.

*Fossil Fuel-fired Generation Facilities.* The Utility's natural gas-fired generation facilities include the Colusa Generating Station, the Gateway Generating Station, and the Humboldt Bay generating station. In addition, the Utility owns and operates three fuel cell sites in the Bay Area.

*Photovoltaic Facilities.* The Utility's operational PV facilities include the Five Points solar station (15 MW), the Westside solar station (15 MW), the Stroud solar station (20 MW), the Huron solar station (20 MW), the Cantua solar station (20 MW), the Giffen solar station (10 MW), the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). All of these facilities are located in Fresno County, except for the Guernsey solar station, which is located in Kings County.

*Generation Resources from Third Parties*

*Qualifying Facility Power Purchase Agreements.* In accordance with the Public Utility Regulatory Policies Act of 1978, the CPUC required electric utilities to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility. QFs primarily include small production facilities whose primary energy sources are co-generation facilities that produce combined heat and power and renewable generation facilities. As of December 31, 2013, the Utility had agreements with 170 QFs that are in operation, which expire at various dates between 2014 and 2028.

*Irrigation Districts and Water Agencies.* The Utility also has entered into agreements with various irrigation districts and water agencies to purchase hydroelectric power. These agreements require the Utility to make semi-annual fixed minimum payments as well as variable payments based on the operating and maintenance costs incurred by the irrigation districts and water agencies. These contracts will expire on various dates between 2014 and 2030.

*Other Third-Party Power Purchase Agreements* . The Utility has entered into several power purchase agreements for renewable and conventional generation resources, including tolling agreements and resource adequacy agreements.

For more information regarding the Utility's power purchase agreements, see Note 14: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

*Renewable Generation Resources*

California law requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers to at least 33% of their total annual retail sales. The RPS program, which became effective in December 2011, established three multi-year compliance periods that have gradually increasing RPS targets: 2011 through 2013, 2014 through 2016, and 2017 through 2020. After 2020, the RPS compliance periods will be annual. In 2013, the California law that established the RPS program was amended to allow the CPUC to set higher RPS targets. The CPUC is conducting a rulemaking proceeding to consider, among other issues, whether and how to increase the RPS targets. Renewable generation resources, for purposes of the RPS program, include bioenergy such as biogas and biomass, certain (primarily small) hydroelectric facilities and efficiency improvements, wind, solar, and geothermal energy. The Utility has made substantial financial commitments under third-party renewable energy contracts to meet its RPS requirements. The Utility forecasts that it will comply with its RPS requirements for the first and second compliance periods based on its current portfolio of executed contracts. The costs incurred by the Utility under third-party contracts to meet RPS requirements are expected to be recovered with other procurement costs through rates. The costs of Utility-owned renewable generation projects will be recoverable through traditional cost-of-service ratemaking mechanisms provided that costs do not exceed the maximum amounts authorized by the CPUC for the respective project.

During 2013, most renewable energy deliveries resulted from third party power purchase agreements and QF agreements. Additional renewable resources included the Utility's small hydroelectric and solar facilities and certain irrigation district contracts (small hydroelectric facilities). (Under California law, generally only small hydroelectric generation resources (30 MW or less) can qualify as a renewable resource for purposes of meeting the RPS mandate, with some exceptions. Most of the Utility's hydroelectric generating units have a capacity in excess of the 30-MW threshold and do not qualify as RPS-eligible resources.)

Total 2013 renewable deliveries are stated in the table below.

| Type | GWh | Percent of Bundled Retail Sales |
|---|---|---|
| Biopower | 3,239 | 4.3% |
| Geothermal | 3,693 | 4.9% |
| Wind | 4,904 | 6.5% |
| RPS-Eligible Hydroelectric | 1,581 | 2.1% |
| Solar | 3,613 | 4.7% |
| Total | 17,030 | 22.5% |

For more information regarding the Utility's renewable energy contracts, see Note 14: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

***Electricity Transmission***

At December 31, 2013, the Utility owned approximately 18,115 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV. The Utility also operated 91 electric transmission substations with a capacity of approximately 62,289 MVA. The Utility's electric transmission system is interconnected with electric power systems in the WECC, which includes many western states, Alberta and British Columbia, Canada, and parts of Mexico.

The CAISO, which is regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. The CAISO also is responsible for ensuring that the reliability of the transmission system is maintained. The Utility acts as its own scheduling coordinator to schedule electricity deliveries to the transmission grid. The Utility also acts as a scheduling coordinator to deliver electricity produced by several governmental entities to the transmission grid under contracts the Utility entered into with these entities before the CAISO commenced operation in 1998. In addition, under the mandatory reliability standards implemented by the FERC, all users, owners, and operators of the transmission system, including the Utility, are also responsible for maintaining reliability through compliance with the reliability standards. See the discussion of reliability standards under "The Utility's Regulatory Environment — Federal Regulation" above.

In November 2013, the Utility, MidAmerican Transmission LLC, and Citizens Energy Corporation were selected by CAISO to develop a new 70-mile transmission line to address the growing power demand in the greater Fresno area. The 230-kV line will span across Fresno, Madera and Kings counties, running from the Gates to Gregg substations, which are owned and operated by the Utility. In addition to increased power, the new line will help reduce the number and duration of power outages, create jobs and support economic development, and bolster efforts to integrate clean, renewable energy onto the grid. The transmission line would be operational no later than 2022 and could come on line earlier.

During 2013, the Utility upgraded several critical substations and re-conductored some transmission lines to improve maintenance and operating flexibility, reliability and safety, including the installation or replacement of 8 transmission substation transformers. The Utility expects to undertake various additional transmission projects over the next few years to upgrade and expand the Utility's transmission system and increase capacity in order to accommodate system load growth, to secure access to renewable generation resources, to replace aging or obsolete equipment, and to improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment following the attack on one of its transmission substations in April 2013 which caused significant damage.

*Electricity Distribution*

The Utility's electricity distribution network consists of approximately 141,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 58 transmission-switching substations, and 603 distribution substations. The Utility's distribution network interconnects with the Utility's transmission system primarily at transmission switching substations and distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

The distribution substations serve as the central hubs of the Utility's electricity distribution network and consist of transformers, voltage regulation equipment, protective devices, and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or other facilities to entities, such as municipal and other utilities, that then resell the electricity. In April 2013, the Utility began construction on the first of three new electric distribution control centers that will house new smart grid technology, enhancing electric reliability for customers. Located in Concord, California, the 37,000-square-foot facility is expected to be completed in 2014.

In 2013, the Utility replaced more than nearly 100,000 feet of underground cable, primarily in San Francisco and East Bay, replaced 100,686 feet of overhead wire, and installed or replaced 19 distribution substation transformer banks to improve reliability and provide capacity to accommodate growing demand. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2014.

*Electricity Operating Statistics*

The following table shows certain of the Utility's operating statistics from 2009 to 2013 for electricity sold or delivered, including the classification of revenues by type of service.

| | 2013 | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|
| Customers (average for the year) | 5,243,216 | 5,214,170 | 5,188,638 | 5,155,724 | 5,137,240 |
| Deliveries (in GWh) (1) | 86,513 | 86,113 | 81,255 | 79,634 | 72,385 |
| Revenues (in millions): | | | | | |
| Residential | $ 5,091 | $ 4,953 | $ 4,778 | $ 4,795 | $ 4,759 |
| Commercial | 4,905 | 4,735 | 4,732 | 4,823 | 4,538 |
| Industrial | 1,388 | 1,408 | 1,379 | 1,424 | 1,392 |
| Agricultural | 1,021 | 901 | 692 | 736 | 770 |
| Public street and highway lighting | 75 | 79 | 77 | 79 | 74 |
| Other | (128) | (11) | 94 | (1,178) | (1,700) |
| Subtotal | 12,352 | 12,065 | 11,752 | 10,679 | 9,833 |
| | | | | | |
| Regulatory balancing accounts | 137 | (51) | (151) | (35) | 424 |
| **Total electricity operating revenues** | $ 12,489 | $ 12,014 | $ 11,601 | $ 10,644 | $ 10,257 |
| Other Data: | | | | | |
| Average annual residential usage (kWh) | 6,752 | 5,961 | 6,799 | 6,843 | 6,953 |
| Average billed revenues (per kWh): | | | | | |
| Residential | $ 0.1643 | $ 0.1594 | $ 0.1548 | $ 0.1560 | $ 0.1524 |
| Commercial | 0.1499 | 0.1449 | 0.1441 | 0.1468 | 0.1377 |
| Industrial | 0.0928 | 0.917 | 0.951 | 0.988 | 0.940 |
| Agricultural | 0.1454 | 0.1458 | 0.1475 | 0.1451 | 0.1327 |
| Net plant investment per customer | $ 6,002 | $ 4,919 | $ 5,045 | $ 4,728 | $ 4,336 |

(1) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

**Natural Gas Utility Operations**

During 2013, the Utility continued to make significant progress on efforts to improve the safety and reliability of its natural gas operations, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's pipeline safety enhancement plan, approved by the CPUC in December 2012, to modernize and upgrade its natural gas transmission system to meet new, industry-wide safety standards. Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011 following their investigations into the San Bruno accident. The Utility has satisfied nine of the twelve NTSB recommendations. The Utility continues to make progress on the remaining three longer-term recommendations.

Since work began on the PSEP and other gas transmission work in 2011, the Utility has verified 657 miles of transmission pipeline through hydrostatic pressure tests or records verification, replaced 127 miles of transmission pipeline, installed 134 automated valves, and collected and digitized more than 3.5 million pipeline records. In July 2013, the Utility completed its search and review of records relating to pipeline pressure validation for all approximately 6,750 miles of its natural gas transmission system. (See the information within MD&A under the heading "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.) In 2013, as part of the Utility's multi-year effort to identify and remove encroachments (e.g. building structures and vegetation overgrowth) from transmission pipeline rights-of-way, the Utility completed a "centerline" mapping survey of its entire gas transmission system to locate, mark, and map the center of all transmission pipelines. The Utility also continued to improve the integrity of transmission pipelines, which included retrofitting approximately 190 miles of pipeline in 2013 to accommodate in-line inspection tools.

The Utility has also implemented a new distribution integrity management program designed to enhance operations and improve the overall safety of the gas distribution system. The Utility has analyzed and replaced a total of 53 miles of Aldyl-A plastic pipeline in 2012 and 2013 and plans to replace 33 additional miles by the end of 2014. It also updated the geographic information system with information on approximately 5,600 miles of Aldyl-A pipeline, including additional pipeline and service attribute information. The Utility completed additional distribution leak surveys in 2013 (in addition to complying with regular distribution leak survey requirements) and repaired approximately 41,000 leaks of all grades.

In August 2013, the Utility opened its new 42,000-square-foot control center in San Ramon, California to monitor and control all aspects of its natural gas system across its service area. The Utility has continued to improve operations by utilizing modern tools and technologies to inspect pipelines, detect gas leaks, and provide real-time access to detailed maps of the Utility's underground gas system. The Utility has improved its supervisory controls and data acquisition system to better detect pipeline leaks and breaks and improve its integrity management program, including incorporating new analysis tools to identify and assess risks to pipeline integrity. The Utility has also implemented a system to enable employees and contractors to report potential pipeline integrity issues and track corrective actions taken. Finally, the Utility has significantly improved the speed at which it responds to gas odor calls.

***Natural Gas System Assets***

The Utility owns and operates an integrated natural gas transportation, storage, and distribution system that includes most of northern and central California. At December 31, 2013, the Utility's natural gas system consisted of approximately 42,559 miles of distribution pipelines, over 6,000 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations which receive, store and move natural gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems. Line 300 interconnects with pipeline systems located in the U.S. Southwest and the Rocky Mountains that are owned by third parties (Transwestern Pipeline Company, El Paso Natural Gas Company, Questar Southern Trails Pipeline Company, and Kern River Pipeline Company). Line 300 has a receipt capacity of approximately 1.1 Bcf per day. Line 400 and 401 interconnect at the California-Oregon border with the pipeline systems owned by GTN and Ruby Pipeline, LLC. This line has a receipt capacity at the border of approximately 2.2 Bcf per day. Through interconnections with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility also is supplied by natural gas fields in California.

The Utility owns and operates three underground natural gas storage fields connected to the Utility's transmission and storage system and has a 25% interest in the new Gill Ranch Storage Field. These storage fields and the Utility's Gill Ranch share have a combined firm capacity of approximately 48.7 Bcf. In addition, three independent storage operators are interconnected to the Utility's northern California transportation system.

***Natural Gas Services***

The CPUC divides the Utility's on-system natural gas customers into two categories for the purpose of determining service reliability: core and non-core customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and small commercial natural gas customers. The non-core customer class is comprised of industrial, large commercial, and electric generation natural gas customers. In 2013, core customers represented more than 99% of the Utility's total natural gas customers and 37% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total natural gas customers and 63% of its total natural gas deliveries. In addition to deliveries discussed above, the Utility delivers gas to off-system customers ( *i.e* ., outside of the Utility's service territory) and to third-party natural gas storage customers.

The Utility provides natural gas transportation services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas procurement service (i.e. , natural gas supply) from either the Utility or alternate energy service providers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more than 91% of core customers, representing nearly 80% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to large non-core customers such as electricity generators, QF co-generators, enhanced oil recovery customers, refiners, and other large non-core customers. However, some smaller non-core customers are permitted to elect to receive core service, including procurement service, from the Utility if they agree to receive such service for a minimum of five years. Core service to non-core customers is subject to these restrictions to protect core procurement customers from price increases that could otherwise result if the Utility incurred costs to reinforce its pipeline system and take other measures to provide core service reliability on a short-term basis to serve new load from non-core customers.

The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers.

*Natural Gas Supplies*

The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated generally based on market conditions. During 2013, the Utility purchased approximately 240,414 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 13% of the total natural gas volume the Utility purchased during 2013.

*Interstate and Canadian Natural Gas Transportation Services Agreements*

The Utility has a number of arrangements with interstate and Canadian third-party transportation service providers to serve core customers' service demands. The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by GTN, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport this gas from the U.S Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border, and firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport this natural gas from supply points in the U.S. Southwest to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnect point with the Utility's natural gas system in the area of Daggett, CA.

*Natural Gas Operating Statistics*

The following table shows the Utility's operating statistics from 2009 through 2013 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

| | 2013 | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|
| Customers (average for the year) | 4,378,797 | 4,353,278 | 4,327,407 | 4,295,741 | 4,271,007 |
| Gas purchased (MMcf) | 240,414 | 247,792 | 279,157 | 270,228 | 264,314 |
| Average price of natural gas purchased | $ 3.29 | $ 2.45 | $ 3.69 | $ 4.07 | $ 3.57 |
| Bundled gas sales (MMcf): | | | | | |
| Residential | 181,775 | 185,376 | 201,109 | 195,195 | 195,217 |
| Commercial | 46,668 | 47,341 | 52,230 | 53,921 | 57,550 |
| **Total** | 228,443 | 232,717 | 253,339 | 249,116 | 252,767 |
| Revenues (in millions): | | | | | |
| Bundled gas sales: | | | | | |
| Residential | $ 1,870 | $ 1,852 | $ 2,089 | $ 1,991 | $ 1,953 |
| Commercial | 395 | 383 | 464 | 474 | 496 |
| Regulatory balancing accounts | 240 | 221 | 295 | 305 | 289 |
| Other | 44 | 66 | 102 | 49 | 55 |
| Bundled gas revenues | 2,549 | 2,522 | 2,950 | 2,819 | 2,793 |
| Transportation service only revenue | 555 | 499 | 400 | 377 | 349 |
| **Operating revenues** | $ 3,104 | $ 3,021 | $ 3,350 | $ 3,196 | $ 3,142 |
| Selected Statistics: | | | | | |
| Average annual residential usage (Mcf) | 44 | 45 | 49 | 48 | 48 |
| Average billed bundled gas sales revenues per Mcf: | | | | | |
| Residential | $ 10.29 | $ 9.99 | $ 10.39 | $ 10.20 | $ 10.00 |
| Commercial | 8.47 | 8.09 | 8.89 | 8.79 | 8.62 |
| Net plant investment per customer | $ 2,234 | $ 1,696 | $ 1,721 | $ 1,637 | $ 1,557 |

**Public Purpose and Customer Programs**

California law has established various public purpose programs related to energy efficiency, energy research and development, and renewable energy resources. These programs include the CSI and other self-generation programs, as discussed under "Self-Generation Incentive Program and California Solar Initiative," below. California law requires the CPUC to authorize funding for these programs through the collection of rate surcharges and other rate components. Additionally, the CPUC has authorized funding for energy savings assistance and demand response programs. For 2013, the Utility was authorized revenue requirements of $724 million from electric customers and $160 million from gas customers to fund public purpose and other programs.

*Energy Efficiency Programs*

The Utility's energy efficiency programs are designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances, other energy-using equipment and energy management products to meet energy savings goals in California. The CPUC has authorized a total of $823 million to fund the Utility's 2013 and 2014 energy efficiency programs, including programs administered by the Marin Energy Authority, a CCA, and a regional network of San Francisco Bay area cities and counties.

On December 20, 2012, the CPUC approved an energy efficiency incentive mechanism to reward the Utility and other California energy utilities for the successful implementation of their 2010-2012 energy efficiency programs. The mechanism provides each utility with an earnings rate composed of a 5% management fee based on qualified program expenditures and an additional performance bonus of up to 1%. The Utility's earnings rate for the 2010-2012 energy efficiency program cycle is 5.68%. The CPUC has awarded the Utility $21 million and $22 million for program years 2010 and 2011, respectively. The utilities will file their incentive claims based on the CPUC-audited 2012 program expenditures in the third quarter of 2014 for approval by the CPUC in the fourth quarter of 2014.

On September 5, 2013, the CPUC approved a new energy efficiency incentive mechanism designed to reward the Utility and the other California investor-owned utilities for the successful implementation of their energy efficiency portfolios for 2013 and beyond. The mechanism provides each utility with an ability to earn shareholder incentives through four separate earnings categories. The mechanism includes a cap on earnings for the Utility of approximately $41 million annually for 2013 and 2014.

*Demand Response Programs*

Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. In April 2012, the CPUC authorized the Utility to collect $192 million to fund its 2012-2014 demand response programs. On January 16, 2014, the CPUC approved a 2015 and 2016 bridge extension of the existing programs while it determines the enhanced role of demand response in meeting California's resource planning needs and operational requirements, with the exact amount of funding to be determined in a future CPUC decision. Pending a decision, funding will remain capped at the same level as the current 2013-2014 demand response budget.

*Self-Generation Incentive Program and California Solar Initiative*

The Utility administers the self-generation incentive program authorized by the CPUC to provide incentives to electricity and gas customers who install certain types of clean or renewable distributed generation and energy storage resources that meet all or a portion of their onsite energy usage. The CPUC approved annual funding for the self-generation incentive program of $36 million through 2014, with any carryover funds to be administered through 2015. The Utility also administers the CSI in its service territory. The CPUC has authorized the Utility to collect approximately $1.1 billion from 2007 through 2016 to fund customer incentives for the installation of retail solar energy projects to serve onsite load, as well as to fund research, development, and demonstration activities, and administration expenses. The current overall objective of this initiative is to install 3,000 MW (through both California investor-owned electric utilities and municipal electric utilities) through 2016. The California legislature approved additional funding of $108 million for the low income CSI program and the CPUC will provide direction on this extension in 2014.

*Low-Income Energy Efficiency Programs and California Alternate Rates for Energy*

The CPUC has authorized the Utility to collect approximately $469 million to support the Utility's energy efficiency programs for low-income and fixed-income customers over 2012 through 2014. The Utility also provides a discount rate called the California Alternate Rates for Energy for low-income customers. This rate subsidy is paid for by the Utility's other customers. During any given year, the extent of the subsidy for customers collectively depends upon the number of customers participating in the program and their actual energy usage. In 2013, the amount of this subsidy was approximately $833 million. The CPUC also authorized the Utility to recover approximately $45 million in administrative costs relating to the California Alternate Rates for Energy subsidy through 2014.

**Enviro nmental Regulation**

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the discharge of pollutants into the air, water, and soil; the reporting and reduction of CO2 and other GHG emissions; the remediation of hazardous and radioactive substances; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify, or replace equipment, acquire permits and/or emission allowances or other emission credits for facility operations and clean-up, or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility's wastes may have been discharged. The actual amount of costs that the Utility will incur is subject to many factors, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, the availability of recoveries or contributions from third parties, and the development of market-based strategies to address climate change. Generally, the Utility has recovered the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a special ratemaking mechanism described in Note 14: Commitments and Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated by reference.

***Air Quality and Climate Change***

The Utility's electricity generation plants, natural gas pipeline operations, fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, SO2, NOx, GHGs, and particulate matter.

*Federal Regulation* . At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted.. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions, including establishing an annual GHG reporting requirement. The Utility files annual GHG emission reports with the EPA covering its electric and gas operations in compliance with the EPA's reporting requirement. In addition, in January 2014, the EPA published draft regulations under section 111(b) of the Clean Air Act to control GHG emissions from new fossil fuel-fired power plants. While these draft regulations as presently written do not apply to the Utility's power plants currently in operation or under construction, it is possible that the final regulations may affect the design, construction, operation and cost of future fossil fuel-fired power plants. The EPA has also announced that it intends to issue draft regulations applicable to GHG emissions from existing power plants under section 111(d) of the Clean Air Act in June of 2014.

*State Regulation.* AB 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB established a state-wide GHG 1990 emissions baseline of 427 million metric tons of CO2 (or its equivalent) to serve as the 2020 emissions limit for the state of California. The CARB has approved various regulations to implement AB 32, including GHG emissions reporting and a state-wide, comprehensive "cap and trade" program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by the major sources of GHG emissions.

The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next three-year compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges in the market for trading GHG allowances. The CARB is allocating a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their electricity-related allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their electricity-related auction revenues among certain classes of their customers. Although the CPUC has previously authorized the utilities to recover their electricity related GHG compliance costs through rates, the recovery of these costs has been temporarily deferred until May 2014. In addition, the CARB may allocate a number of allowances for free to natural gas suppliers, including the Utility, for the benefit of the Utility's natural gas customers. In anticipation of the Utility's expanded compliance obligations for natural gas suppliers beginning January 1, 2015, the Utility has filed requests at the CPUC for authority to recover the natural gas supplier-related compliance costs from natural gas customers on an annual basis effective January 1, 2015. The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

Increasing use of renewable energy supplies also is expected to help reduce GHG emissions in California. (For more information, see "Renewable Generation Resources" above.)

*Climate Change Mitigation and Adaptation Strategies.* During 2013, the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to develop its strategy to plan for the actions that it will need to take to adapt to the likely impacts that climate change will have on the Utility's future operations. With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme and frequent hot weather events. Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. This impact could, in turn, affect the Utility's hydroelectric generation. At this time, the Utility does not anticipate that reductions in Sierra Nevada snowpack will have a significant impact on its hydroelectric generation, due in large part to its adaptation strategies. For example, one adaptation strategy the Utility is developing is a combination of operating changes that may include, but are not limited to, higher winter carryover reservoir storage levels, reduced conveyance flows in canals and flumes in response to an increased portion of precipitation falling as rain rather than snow, and reduced discretionary reservoir water releases during the late spring and summer. If the Utility is not successful in fully adapting to projected reductions in snowpack over the coming decades, it may become necessary to replace some of its hydroelectric generation with electricity from other sources, including GHG-emitting natural gas-fired power plants.

With respect to natural gas operations, both safety-related pipeline hydrotesting/strength testing and normal pipeline maintenance and operations, releases the GHG methane to the atmosphere. The Utility has taken proactive steps to reduce the release of methane by implementing techniques including drafting and cross-compression which reduces the pressures and volumes of natural gas within pipelines prior to venting. In addition, the Utility continues to replace a substantial portion of its older cast iron, steel and plastic distribution pipelines and steel gas transmission mains with new pipe, which reduces leakage. In 2013, the Utility implemented a proactive natural gas leak repair program, 40,676 gas leaks were identified, graded, prioritized and repaired. The primary reason for this effort was public safety, however, eliminating gas leaks results in a positive impact to the environment.

The Utility believes its strategies to reduce GHG emissions—such as energy efficiency and demand response programs, infrastructure improvements, and the support of renewable energy development—are also effective strategies for adapting to the expected increased demand for electricity in extreme hot weather events likely to result from climate change. PG&E Corporation and the Utility are also assessing the benefits and challenges associated with various climate change policies and identifying how a comprehensive program can be structured to mitigate overall costs to customers and the economy as a whole while ensuring that the environmental objectives of the program are met.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. As a result of the time necessary for a thorough, third-party verification of the Utility's GHG emissions, emissions data for 2012 are the most recent data available. The Utility reports its GHG emissions to the CARB. The Utility also voluntarily reports its GHG emissions to The Climate Registry, a non-profit organization that has a reporting and measurement standard applicable to most industry sectors across North America, which enables the Utility to publicly report GHG emissions not covered by mandatory reporting requirements. The Utility's third-party verified voluntary GHG inventory for 2012 totaled more than 57 million metric tonnes of CO2-e, which includes approximately 38 million metric tonnes CO2-e from customer natural gas use.

Beginning with its 2010 emissions, the Utility reports the GHG emissions from its facilities and operations to the EPA under its mandatory reporting requirements. PG&E Corporation and the Utility also publish third-party-verified GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

***2012 Emissions Reported to the California Air Resources Board***

The following table shows the GHG emissions data the Utility reported to the CARB under AB 32.

| **Source** | **Amount (metric tonnes CO2 – equivalent)** |
|---|---|
| Fossil Fuel-Fired Plants (1) | 2,466,851 |
| Natural Gas Compressor Stations (2) | 351,878 |
| Distribution Fugitive Natural Gas Emissions | 222,995 |
| Customer Natural Gas Use (3) | 42,434,940 |
| Total | 45,476,664 |

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations; does not include de minimis emissions.

(2) Includes compressor stations emitting more than 25,000 metric tonnes of CO2-e annually; does not include de minimis emissions.

(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other nat local distribution companies. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value fuel that is delivered to covered entities as calculated by the CARB.

***Benchmarking GHG Emissions for Delivered Electricity***

The Utility's third-party-verified CO2 emissions rate associated with the electricity delivered to customers in 2012 was 445 pounds of CO2 per MWh. The Utility's 2012 emissions rate as compared to the national and California averages for electric utilities is shown in the following table:

| | **Amount (Pounds of CO2 per MWh)** |
|---|---|
| U.S. Average (1) | 1,216 |
| California's Average (1) | 659 |
| Pacific Gas and Electric Company (2) | 445 |

(1) Source: Environmental Protection Agency eGRID 2012 Version 1.0, which contains year 2009 information configured to reflect the electric power industry's curr structure as of May 10, 2012. This is the most up-to-date information available from EPA.

(2) Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's total emissions and the Utility's emission rate for delivered electricity.

***Emissions Data for Utility-Owned Generation***

In addition to GHG emissions data provided above, the table below sets forth information about the GHG and other emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised more than 40% of the Utility's delivered electricity in 2012. The Utility's fossil fuel-fired generation comprised approximately 8% of the Utility's delivered electricity in 2012.

| | **2012** | **2011** |
|---|---|---|
| Total NOx Emissions (tons) | 158 | 144 |
| NOx Emissions Rates (pounds/MWh) | | |
| Fossil Fuel-Fired Plants | 0.05 | 0.06 |
| All Plants | 0.01 | 0.008 |
| Total SO2 Emissions (tons) | 15 | 12 |
| SO2 Emissions Rates (pounds/MWh) | | |
| Fossil Fuel-Fired Plants | 0.005 | 0.005 |
| All Plants | 0.0009 | 0.0007 |
| Total CO2 Emissions (metric tons) | 2,464,464 | 2,024,206 |
| CO2 Emissions Rates (pounds/MWh) | | |
| Fossil Fuel-Fired Plants | 864 | 875 |
| All Plants | 172 | 126 |
| Other Emissions Statistics | | |
| Sulfur Hexafluoride Emissions | | |
| Total Sulfur Hexafluoride Emissions (metric tons CO2-e) | 63,127 | 70,052 |
| Sulfur Hexafluoride Emissions Leak Rate | 1.5% | 1.7% |

***Water Quality***

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The California Water Board has appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at nuclear power plants, including Diablo Canyon. The committee's consultant is expected to submit a final report to the California Water Board in 2014. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

***Hazardous Waste Compliance and Remediation***

The Utility's facilities are subject to the requirements issued by the EPA under the federal Resource Conservation and Recovery Act and the CERCLA, as well as other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site, and in some cases corporate successors to the operators or arrangers. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources, and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility generates waste that falls within CERCLA's definition of hazardous substances and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility has a comprehensive program in place to comply with federal, state, and local laws and regulations related to hazardous materials and hazardous waste compliance, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility’s remediation activities are overseen by the California Department of Toxic Substances Control, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. For more information about environmental remediation liabilities, see the sections within MD&A entitled “Environmental Matters,” “Critical Accounting Polices,” and Note 14: Commitments and Contingencies−Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

*Generation Facilities*

Operations at the Utility's current and former generation facilities may have resulted in contaminated soil or groundwater. Although the Utility sold most of its geothermal and fossil fuel-fired plants, in many cases the Utility retained pre-closing environmental liability under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies. Fossil fuel-fired Units 1 and 2 of the Utility’s Humboldt Bay power plant shut down in September 2010, and are now in the decommissioning process along with the nuclear Unit 3, which was shut down in 1976. The Utility has entered into a voluntary cleanup agreement with the California Department of Toxic Substances Control and is currently completing a soil and groundwater investigation to determine what soil and groundwater remediation may be necessary.

*Former Manufactured Gas Plant Sites*

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain retired MGP sites. During their operation, from the mid-1800s through the early 1900s, MGPs produced lampblack and coal tar residues. The residues from these operations, which may remain at some sites, contain chemical compounds that now are classified as hazardous. The Utility has been coordinating with environmental agencies and third-party owners to evaluate and take appropriate action to mitigate any potential environmental concerns at 41 MGP sites that the Utility owned or operated in the past.

*Natural Gas Compressor Stations*

Groundwater at the Utility’s Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility’s past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment. The Utility has incurred significant environmental liabilities associated with these sites. For more information about the Utility’s remediation and abatement efforts and related liabilities, see Note 14: Commitments and Contingencies−Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

***Nuclear Fuel Disposal***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay Unit 3. As a result, the Utility constructed an interim dry cask storage facility to store spent fuel at Diablo Canyon through at least 2024, and a separate facility at Humboldt Bay. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

On September 5, 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. In 2013, the Utility was awarded an additional $29 million for costs incurred between January 2011 and May 2012. These proceeds were recorded in a regulatory balancing account and are being refunded to customers through rates. On January 31, 2014, the U.S. Department of Justice and the Utility executed an addendum extending the term of the settlement agreement for an additional three years, through 2016. The amended settlement agreement does not address costs incurred for spent fuel storage after 2016 and such costs could be the subject to future litigation. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

***Nuclear Decommissioning***

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover the estimated costs through rates. Nuclear decommissioning charges collected through rates are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennal Proceeding in the section of MD&A entitled "Regulatory Matters−Diablo Canyon Nuclear Power Plant" and Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.)

***Endangered Species***

Many of the Utility's facilities and operations are located in, or pass through, areas that are designated as critical habitats for federal, or state-listed endangered, threatened, or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated at or near the Utility's facilities or operations. The Utility is seeking to secure "habitat conservation plans" to ensure long-term compliance with state and federal endangered species acts. The Utility expects that it will be able to recover costs of complying with state and federal endangered species acts through rates.

## ITEM 1A. Risk Factors

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility appears within MD&A under the heading "Risk Factors" in the 2013 Annual Report, which information is incorporated herein by reference.

## ITEM 1B. Unresolved Staff Comments

None.

## ITEM 2. Properties

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described above under "Electric Utility Operations" and "Natural Gas Utility Operations" which information is incorporated herein by reference. The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11.0 million square feet of real property, including 8.6 million square feet that the Utility owns. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California. PG&E Corporation also has entered into leases for approximately 87,000 square feet of office space in San Francisco, California. Leases for 40,000 square feet will expire in 2014 and the remaining leases will expire in 2022.

The Utility currently owns approximately 170,000 acres of land, including approximately 140,000 acres of watershed lands. Pursuant to its 2002 Settlement Agreement with the CPUC, the Utility agreed to permanently preserve six “beneficial public values” on all its watershed lands through conservation easements or equivalent protections, and to make up to 44,000 acres of its watershed lands available for donation to public entities or qualified non-profit conservation organizations through its Land Conservation Commitment. The Utility will not donate watershed lands that contain the Utility's or a joint licensee's hydroelectric generation facilities, but this land will be encumbered with conservation easements. Pursuant to the 2002 Settlement Agreement, the Pacific Forest Watershed Lands Stewardship Council was formed to oversee the development and implementation of a Land Conservation Plan that articulates the long-term management objectives for these watershed lands. The Council is governed by an 18-member board of directors, one of whom is appointed by the Utility. The other members represent a range of diverse stakeholders in the watershed lands. The Utility’s goal is to implement all the Land Conservation Commitment transactions by the end of 2017, subject to securing all required regulatory approvals.

**ITEM 3. Legal Proceedings**

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation’s and the Utility’s liability for legal matters, see Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

***Diablo Canyon Power Plant***

The Utility's Diablo Canyon power plant employs a “once-through” cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

The EPA published draft regulations in April 2011 to implement the requirements of SECTION 316(b) of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations. As part of the implementation process for the California Water Resources Control Board’s once-through cooling policy, the California Water Board’s nuclear review committee is overseeing development of an alternative technology assessment for Diablo Canyon. The committee’s consultant is expected to submit its final report to the California Water Board in 2014. The California Water Board’s policy on once-through cooling and the EPA’s final regulations could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (See “Item 1. Business−Environmental Matters−Water Quality” above.) PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on their Utility's financial condition or results of operations.

*Litigation Related to the San Bruno Accident and Natural Gas Spending*

Following the San Bruno accident various lawsuits were filed in San Mateo County Superior Court against PG&E Corporation and the Utility to seek compensation for personal injury and property damage, and other relief, including punitive damages. In 2011 and 2012 , the Utility entered into settlement agreements to resolve many of the claims and In September 2013, the Utility agreed to settle the claims of substantially all of the remaining plaintiffs who sought compensation. At December 31, 2013, the Utility has recorded cumulative charges of $565 million as its best estimate of probable loss for third-party claims related to the San Bruno accident and has made cumulative payments of $520 million to third-party claimants.

At December 31, 2013, there were also four purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits have filed a consolidated complaint with the San Mateo County Superior Court. The court has lifted the stay on these proceedings for the limited purpose of allowing the parties to exchange information and discuss possible resolution. A case management conference is scheduled for April 18, 2014. The remaining purported shareholder derivative lawsuit, filed in the U.S. District Court for the Northern District of California, remains stayed. PG&E Corporation and the Utility are uncertain when and how these derivative lawsuits will be resolved.

In addition, on August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. PG&E Corporation and the Utility contest the allegations.

For additional information, see the discussion within MD&A under the heading, "Natural Gas Matters" and in Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements contained in the 2013 Annual Report, which discussions are incorporated herein by reference.

*Pending CPUC Investigations*

There are three CPUC investigative enforcement proceedings pending against the Utility related to the Utility's natural gas operations and the San Bruno accident. Evidentiary hearings and briefing on the issue of alleged violations have been completed in each of these investigations. The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.950 billion of non-recoverable costs to perform work under the Utility's pipeline safety enhancement plan and to implement the operational remedies. Several other parties have also submitted penalty recommendations. The administrative law judges who oversee the investigation are expected to issue one or more presiding officers' decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued.

For more information, see discussions within MD&A under the heading, "Natural Gas Matters," and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which discussions are incorporated herein by reference.

*Other CPUC Enforcement Matters*

The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility's operations or otherwise. In January 2012, the SED imposed fines of $16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from $50,000 to $8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately $14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. On January 23, 2014, the Utility filed an application for rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable.

In addition, the Utility has notified the CPUC and the SED that the Utility is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments from pipeline rights-of-way over a multi-year period. The SED could impose penalties on the Utility or take other enforcement action in connection with this matter.

***Criminal Investigation***

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. A criminal charge or finding would further harm the Utility's reputation. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

See the discussions within MD&A under the heading "Natural Gas Matters – Criminal Investigation," and in Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which discussions are incorporated herein by reference.

**ITEM 4. Mine Safety Disclosures**

Not applicable.

## EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of PG&E Corporation "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 3, 2014 were as follows.

| Name | Age | Position |
|---|---|---|
| Anthony F. Earley, Jr. | 64 | Chairman of the Board, Chief Executive Officer, and President |
| Kent M. Harvey | 55 | Senior Vice President and Chief Financial Officer |
| Christopher P. Johns | 53 | President, Pacific Gas and Electric Company |
| Hyun Park | 52 | Senior Vice President and General Counsel |
| Greg S. Pruett | 56 | Senior Vice President, Corporate Affairs |
| John R. Simon | 49 | Senior Vice President, Human Resources |

All officers of PG&E Corporation serve at the pleasure of the Board of Directors of PG&E Corporation. During at least the past five years through February 3, 2014, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

| Name | Position | Period Held Office |
|---|---|---|
| Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President | September 13, 2011 to present |
| | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| | Chairman of the Board and Chief Executive Officer, DTE Energy Company | August 1998 to September 30, 2010 |
| Kent M. Harvey | Senior Vice President and Chief Financial Officer | August 1, 2009 to present |
| | Senior Vice President, Financial Services, Pacific Gas and Electric Company | August 1, 2009 to present |
| | Senior Vice President and Chief Risk and Audit Officer | October 1, 2005 to July 31, 2009 |
| Christopher P. Johns | President, Pacific Gas and Electric Company | August 1, 2009 to present |
| | Senior Vice President and Chief Financial Officer | May 1, 2009 to July 31, 2009 |
| | Senior Vice President, Financial Services, Pacific Gas and Electric Company | May 1, 2009 to July 31, 2009 |
| | Senior Vice President, Chief Financial Officer, and Treasurer | October 4, 2005 to April 30, 2009 |
| | Senior Vice President and Treasurer, Pacific Gas and Electric Company | June 1, 2007 to April 30, 2009 |
| Hyun Park | Senior Vice President and General Counsel | November 13, 2006 to present |
| Greg S. Pruett | Senior Vice President, Corporate Affairs | November 1, 2009 to present |
| | Senior Vice President, Corporate Affairs, Pacific Gas and Electric Company | November 1, 2009 to present |
| | Senior Vice President, Corporate Relations | November 1, 2007 to October 31, 2009 |
| | Senior Vice President, Corporate Relations, Pacific Gas and Electric Company | March 1, 2009 to October 31, 2009 |
| John R. Simon | Senior Vice President, Human Resources | April 16, 2007 to present |
| | Senior Vice President, Human Resources, Pacific Gas and Electric Company | April 16, 2007 to present |

The names, ages and positions of the Utility's "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 3, 2014 were as follows:

| Name | Age | Position |
|---|---|---|
| Anthony F. Earley, Jr. | 64 | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation |
| Christopher P. Johns | 53 | President |
| Nickolas Stavropoulos | 55 | Executive Vice President, Gas Operations |
| Geisha J. Williams | 52 | Executive Vice President, Electric Operations |
| Karen A. Austin | 52 | Senior Vice President and Chief Information Officer |
| Desmond A. Bell | 51 | Senior Vice President, Safety and Shared Services |
| Thomas E. Bottorff | 60 | Senior Vice President, Regulatory Affairs |
| Helen A. Burt | 57 | Senior Vice President and Chief Customer Officer |
| John T. Conway | 56 | Senior Vice President, Energy Supply |
| Edward D. Halpin | 52 | Senior Vice President and Chief Nuclear Officer |
| Kent M. Harvey | 55 | Senior Vice President, Financial Services |
| Gregory K. Kiraly | 49 | Senior Vice President, Electric Distribution Operations |
| Hyun Park | 52 | Senior Vice President and General Counsel, PG&E Corporation |
| Greg S. Pruett | 56 | Senior Vice President, Corporate Affairs |
| John R. Simon | 49 | Senior Vice President, Human Resources |
| Jesus Soto, Jr. | 46 | Senior Vice President, Engineering, Construction & Operations |
| Fong Wan | 52 | Senior Vice President, Energy Procurement |
| Dinyar B. Mistry | 51 | VVice President, Chief Financial Officer, and Controller |

All officers of the Utility serve at the pleasure of the Board of Directors of the Utility. During at least the past five years through February 3, 2014, the executive officers of the Utility had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Position | Period Held Office |
|---|---|---|
| Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation | September 13, 2011 to present |
| | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| | Chairman of the Board and Chief Executive Officer, DTE Energy Company | August 1998 to September 30, 2010 |
| Christopher P. Johns | President | August 1, 2009 to present |
| | Senior Vice President, Financial Services | May 1, 2009 to July 31, 2009 |
| | Senior Vice President and Chief Financial Officer, PG&E Corporation | May 1, 2009 to July 31, 2009 |
| | Senior Vice President and Treasurer | June 1, 2007 to April 30, 2009 |
| | Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation | October 4, 2005 to April 30, 2009 |
| Nickolas Stavropoulos | Executive Vice President, Gas Operations | June 13, 2011 to present |
| | Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid | August 2007 to March 31, 2011 |
| Geisha J. Williams | Executive Vice President, Electric Operations | June 1, 2011 to present |
| | Senior Vice President, Energy Delivery | December 1, 2007 to May 31, 2011 |
| Karen A. Austin | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| | President, Consumer Electronics, Sears Holdings | February 2009 to May 2011 |
| | Executive Vice President, Chief Information Officer, Sears Holdings | March 2005 to January 2009 |

| | | |
|---|---|---|
| Desmond A. Bell | Senior Vice President, Safety and Shared Services<br>Senior Vice President, Shared Services and Chief Procurement Officer<br>Vice President, Shared Services and Chief Procurement Officer | January 1, 2012 to present<br>October 1, 2008 to December 31, 2011<br>March 1, 2008 to September 30, 2008 |
| Thomas E. Bottorff | Senior Vice President, Regulatory Affairs<br>Senior Vice President, Regulatory Relations | September 1, 2012 to present<br>October 14, 2005 to August 31, 2012 |
| Helen A. Burt | Senior Vice President and Chief Customer Officer | February 27, 2006 to present |
| John T. Conway | Senior Vice President, Energy Supply<br>Senior Vice President, Energy Supply and Chief Nuclear Officer<br>Senior Vice President, Generation and Chief Nuclear Officer<br>Senior Vice President and Chief Nuclear Officer | March 1, 2012 to present<br>April 1, 2009 to February 29, 2012<br>October 1, 2008 to March 31, 2009<br>March 1, 2008 to September 30, 2008 |
| Edward D. Halpin | Senior Vice President and Chief Nuclear Officer<br>President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company<br>Chief Nuclear Officer, South Texas Project Nuclear Operating Company | April 2, 2012 to present<br>December 2009 to March 2012<br>October 2008 to November 2009 |
| Kent M. Harvey | Senior Vice President, Financial Services<br>Senior Vice President and Chief Financial Officer, PG&E Corporation<br>Senior Vice President and Chief Risk and Audit Officer, PG&E Corporation | August 1, 2009 to present<br>August 1, 2009 to present<br>October 1, 2005 to July 31, 2009 |
| Gregory K. Kiraly | Senior Vice President, Electric Distribution Operations<br>Vice President, Electric Distribution Operations<br>Vice President, SmartMeter Operations<br>Vice President, Electric Maintenance and Construction<br>Vice President, Transmission Substations, Maintenance and Construction | September 18, 2012 to present<br>October 1, 2011 to September 17, 2012<br>August 23, 2010 to September 30, 2011<br>January 1, 2010 to August 22, 2010<br>January 1, 2009 to December 31, 2009 |
| Hyun Park | Senior Vice President and General Counsel, PG&E Corporation | November 13, 2006 to present |
| Greg S. Pruett | Senior Vice President, Corporate Affairs<br>Senior Vice President, Corporate Affairs, PG&E Corporation<br>Senior Vice President, Corporate Relations<br>Senior Vice President, Corporate Relations, PG&E Corporation | November 1, 2009 to present<br>November 1, 2009 to present<br>March 1, 2009 to October 31, 2009<br>November 1, 2007 to October 31, 2009 |
| John R. Simon | Senior Vice President, Human Resources<br>Senior Vice President, Human Resources, PG&E Corporation | April 16, 2007 to present<br>April 16, 2007 to present |
| Jesus Soto, Jr. | Senior Vice President, Engineering, Construction & Operations<br>Senior Vice President, Gas Transmission Operations<br>Vice President, Operations Services, El Paso Pipeline Group | September 2013 to present<br>May 29, 2012 to September 2013<br>May 2007 to May 2012 |
| Fong Wan | Senior Vice President, Energy Procurement | October 1, 2008 to present |
| Dinyar B. Mistry | Vice President, Chief Financial Officer, and Controller<br>Vice President and Controller, PG&E Corporation<br>Vice President and Controller<br>Vice President and Chief Risk and Audit Officer<br>Vice President and Chief Risk and Audit Officer, PG&E Corporation<br>Vice President, Internal Auditing/Compliance and Ethics, PG&E Corporation | October 1, 2011 to present<br>March 8, 2010 to present<br>March 8, 2010 to September 30, 2011<br>September 16, 2009 to March 7, 2010<br>August 1, 2009 to March 7, 2010<br>January 1, 2009 to July 31, 2009 |

## PART II

### ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

As of February 3, 2014, there were 64,972 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2013 Annual Report, which information is incorporated herein by reference. Shares of common stock of the Utility are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility is set forth in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, Note 5: Common Stock and Share-Based Compensation−Dividends of the Notes to the Consolidated Financial Statements, and within MD&A under the heading "Liquidity and Financial Resources—Dividends," in the 2013 Annual Report, which information is incorporated herein by reference.

***Sales of Unregistered Equity Securities***

During the quarter ended December 31, 2013, PG&E Corporation made equity contributions totaling $305 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2013.

***Issuer Purchases of Equity Securities***

During the quarter ended December 31, 2013, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2013, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

### ITEM 6. Selected Financial Data

Selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2013 Annual Report, which information is incorporated herein by reference.

### ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" as well as the "Glossary" in the 2013 Annual Report, which discussion is incorporated herein by reference.

### ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is set forth within MD&A under the heading "Risk Management Activities," and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

### ITE M 8. Financial Statements and Supplementary Data

Information responding to Item 8 is set forth under the following headings for PG&E Corporation: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity" in the 2013 Annual Report and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," and "Reports of Independent Registered Public Accounting Firm" in the 2013 Annual Report, which information is incorporated herein by reference.

**ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure**

Not applicable.

**ITEM 9A. Controls and Procedures**

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2013, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in the 2013 Annual Report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," which information is incorporated by reference and included in Exhibit 13 to this report.

**ITE M 9B. Other Information**

Not applicable.

## PART III

### ITEM 10 . Directors, Executive Officers and Corporate Governance

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this report. Other information regarding directors is set forth under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act is included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on PG&E Corporation's website *www.pgecorp.com* , and the Utility's website, *www.pge.com* : (1) the codes of conduct and ethics adopted by PG&E Corporation and the Utility applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and the Utility that apply to their respective Chief Executive Officers, Chief Financial Officers, or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within four business days of the waiver.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

During 2013 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial expert" as defined by the SEC is set forth under the headings "Corporate Governance – Board Committee Duties – Audit Committees" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

### ITEM 11 . Executive Compensation

Information responding to Item 11, for each of PG&E Corporation and the Utility, is set forth under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2013," "Grants of Plan-Based Awards in 2013," "Outstanding Equity Awards at Fiscal Year End - 2013," "Option Exercises and Stock Vested During 2013," "Pension Benefits – 2013," "Non-Qualified Deferred Compensation – 2013," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2013 Director Compensation" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters**

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Equity Compensation Plan Information***

The following table provides information as of December 31, 2013 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a)) |
|---|---|---|---|
| Equity compensation plans approved by shareholders | 6,194,819(1) | $ 32.98 | 3,310,474(2) |
| Equity compensation plans not approved by shareholders | - | - | - |
| Total equity compensation plans | 6,194,819(1) | $ 32.98 | 3,310,474(2) |

(1) Includes 46,185 phantom stock units, 2,329,256 restricted stock units and 3,566,966 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For a description of these performance shares, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which description is incorporated herein by reference. For performance shares, amounts reflected in this table assume payout in shares at 200% of target. The actual number of shares issued can range from 0% to 200% of target depending on achievement of total shareholder return objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) Represents the total number of shares available for issuance under the LTIP and the 2006 LTIP as of December 31, 2013. Outstanding stock-based awards granted under the LTIP include stock options, and phantom stock. The LTIP expired on December 31, 2005. The 2006 LTIP, which became effective on January 1, 2006, authorizes up to 12 million shares to be issued pursuant to awards granted under the 2006 LTIP. Outstanding stock-based awards granted under the 2006 LTIP include stock options, restricted stock, restricted stock units, phantom stock and performance shares. For a description of the 2006 LTIP, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which description is incorporated herein by reference.

**ITE M 13. Certain Relationships and Related Transactions, and Director Independence**

Information responding to Item 13, for each of PG&E Corporation and the Utility, is included under the headings "Related Party Transactions" and "Corporate Governance – Board and Director Independence and Qualifications" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 14. Principal Accountant Fees and Services**

Information responding to Item 14, for each of PG&E Corporation and the Utility, is set forth under the heading "Information Regarding the Independent Registered Public Accounting Firm for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## PART IV

### ITEM 15. Exhibits and Financial Statement Schedules

**(a) The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and reports of independent registered public accounting firm are contained in the 2013 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2013 and 2012 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2013, 2012, and 2011 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2013, 2012, and 2011 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules and report of independent registered public accounting firm are filed as part of this report:

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2013 and 2012 and for the Years Ended December 31, 2013, 2012, and 2011.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2013, 2012, and 2011.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

3. Exhibits required by Item 601 of Regulation S-K

| Exhibit Number | Exhibit Description |
|---|---|
| 2.1 | Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1) |
| 2.2 | Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2) |
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of June 19, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of June 19, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 3.2) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility's issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility's issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility's issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility's issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |

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| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |

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| 4.17 | Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1) |
| 4.20 | First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2) |
| 10.1 | Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.4 | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |

| | | |
|---|---|---|
| 10.5 | | Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation’s and Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9) |
| 10.6 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.11 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.12 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.13 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.14 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5) |
| 10.15 | * | Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.16 | * | Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18) |
| 10.17 | * | Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18) |
| 10.18 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |

| | | |
|---|---|---|
| 10.19 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.20 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.21 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.22 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.23 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.24 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.25 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.26 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.27) |
| 10.27 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.28 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.29 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.30 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.31 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30) |
| 10.32 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |

| | | |
|---|---|---|
| 10.33 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.34 | * | Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36) |
| 10.35 | * | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37) |
| 10.36 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.37 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.38 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.39 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.40 | * | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.41 | * | Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.42 | * | Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2) |
| 10.43 | * | Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.44 | * | Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.45 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.46 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |

| | | |
|---|---|---|
| 10.47 | * | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.48 | * | Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.49 | * | Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.50 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.51 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.52 | * | PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6) |
| 10.53 | * | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.54 | * | PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51) |
| 10.55 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.56 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.57 | * | PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1) |
| 10.58 | * | PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39) |
| 10.59 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.60 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.61 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |

| | |
|---|---|
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 13 | The following portions of the 2013 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: “Selected Financial Data,” “Glossary,” “Management's Discussion and Analysis of Financial Condition and Results of Operations,” financial statements of PG&E Corporation entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Equity,” financial statements of Pacific Gas and Electric Company entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity,” “Notes to the Consolidated Financial Statements,” “Quarterly Consolidated Financial Data (Unaudited),” “Management's Report on Internal Control Over Financial Reporting,” and “Report of Independent Registered Public Accounting Firm.” |
| 21 | Subsidiaries of the Registrant |
| 23 | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | Powers of Attorney |
| 31.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.
** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

## SIGNATURES

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2013 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| PG&E CORPORATION (Registrant) | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) |
|---|---|
| By: ANTHONY F. EARLEY, JR. | By: CHRISTOPHER P. JOHNS |
| Anthony F. Earley, Jr. | Christopher P. Johns |
| Chairman of the Board, Chief Executive Officer, and President | President |
| Date: February 11, 2014 | Date: February 11, 2014 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| **A. Principal Executive Officers** | | |
| ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation) | February 11, 2014 |
| CHRISTOPHER P. JOHNS<br>Christopher P. Johns | President (Pacific Gas and Electric Company) | February 11, 2014 |
| **B. Principal Financial Officers** | | |
| KENT M. HARVEY<br>Kent M. Harvey | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 11, 2014 |
| DINYAR B. MISTRY<br>Dinyar B. Mistry | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 11, 2014 |
| **C. Principal Accounting Officer** | | |
| DINYAR B. MISTRY<br>Dinyar B. Mistry | Vice President and Controller (PG&E Corporation)<br>Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 11, 2014 |
| **D. Directors** | | |
| *LEWIS CHEW<br>Lewis Chew | Director | February 11, 2014 |

| | | |
|---|---|---|
| *C. LEE COX<br>C. Lee Cox | Director | February 11, 2014 |
| *ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Director | February 11, 2014 |
| *FRED J. FOWLER<br>Fred J. Fowler | Director | February 11, 2014 |
| *MARYELLEN C. HERRINGER<br>Maryellen C. Herringer | Director | February 11, 2014 |
| *CHRISTOPHER P. JOHNS<br>Christopher P. Johns | Director (Pacific Gas and Electric Company only) | February 11, 2014 |
| *RICHARD C. KELLY | Director | February 11, 2014 |
| *ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 11, 2014 |
| *RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 11, 2014 |
| *FORREST E. MILLER<br>Forrest E. Miller | Director | February 11, 2014 |
| *ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 11, 2014 |
| *BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 11, 2014 |
| *BARRY LAWSON WILLIAMS<br>Barry Lawson Williams | Director | February 11, 2014 |

*By: HYUN PARK
HYUN PARK, Attorney-in-Fact

**REPO RT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, and the Company's and the Utility's internal control over financial reporting as of December 31, 2013, and have issued our reports thereon dated February 11, 2014 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties); such consolidated financial statements and reports are included in your 2013 Annual Report to Shareholders of the Company and the Utility and are incorporated herein by reference. Our audits also included the consolidated financial statement schedules of the Company and Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 11, 2014

**PG&E CORPORATION**
**SCHED ULE I — CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**
**(in millions, except per share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Administrative service revenue | $ 41 | $ 43 | $ 44 |
| Operating expenses | (42) | (41) | (44) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (25) | (22) | (22) |
| Other income | (57) | (39) | (17) |
| Equity in earnings of subsidiaries | 848 | 817 | 852 |
| Income before income taxes | 766 | 759 | 814 |
| Income tax benefit | 48 | 57 | 30 |
| Net income | $ 814 | $ 816 | $ 844 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans (net of taxes of $80, $72, $9, at respective dates) | 113 | 108 | (11) |
| Other (net of taxes of $26, $3, and $0, at respective dates) | 38 | 4 | - |
| Total other comprehensive income (loss) | 151 | 112 | (11) |
| Comprehensive Income | $ 965 | $ 928 | $ 833 |
| Weighted average common shares outstanding, basic | 444 | 424 | 401 |
| Weighted average common shares outstanding, diluted | 445 | 425 | 402 |
| Net earnings per common share, basic | $ 1.83 | $ 1.92 | $ 2.10 |
| Net earnings per common share, diluted | $ 1.83 | $ 1.92 | $ 2.10 |

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 231 | $ 207 |
| Advances to affiliates | 30 | 26 |
| Income taxes receivable | 13 | 33 |
| Other current assets | 86 | - |
| **Total current assets** | 360 | 266 |
| **Noncurrent Assets** | | |
| Equipment | 2 | 1 |
| Accumulated depreciation | (1) | (1) |
| Net equipment | 1 | - |
| Investments in subsidiaries | 14,711 | 13,387 |
| Other investments | 110 | 102 |
| Income taxes receivable | 5 | 5 |
| Deferred income taxes | 188 | 178 |
| Other | - | 1 |
| **Total noncurrent assets** | 15,015 | 13,673 |
| **Total Assets** | $ 15,375 | $ 13,939 |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 260 | $ 120 |
| Long-term debt, classified as current | 350 | - |
| Accounts payable – other | 66 | 48 |
| Other | 230 | 221 |
| **Total current liabilities** | 906 | 389 |
| **Noncurrent Liabilities** | | |
| Long-term debt | - | 349 |
| Other | 127 | 127 |
| **Total noncurrent liabilities** | 127 | 476 |
| **Common Shareholders' Equity** | | |
| Common stock | 9,550 | 8,428 |
| Reinvested earnings | 4,742 | 4,747 |
| Accumulated other comprehensive income (loss) | 50 | (101) |
| **Total common shareholders' equity** | 14,342 | 13,074 |
| **Total Liabilities and Shareholders' Equity** | $ 15,375 | $ 13,939 |

**PG&E CORPORATION**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| **Cash Flows from Operating Activities:** | | | |
| Net income | $ 814 | $ 816 | $ 844 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 54 | 51 | 36 |
| Equity in earnings of subsidiaries | (848) | (817) | (852) |
| Deferred income taxes and tax credits, net | (10) | (31) | (26) |
| Noncurrent income taxes receivable/payable | - | (6) | (47) |
| Current income taxes receivable/payable | 20 | (82) | 49 |
| Other | (20) | 20 | (80) |
| **Net cash provided by (used in) operating activities** | 10 | (49) | (76) |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (1,371) | (1,023) | (759) |
| Dividends received from subsidiaries [1] | 716 | 716 | 716 |
| Proceeds from tax equity investments | 275 | 228 | 129 |
| Other | (8) | - | - |
| **Net cash provided by (used in) investing activities** | (388) | (79) | 86 |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings under revolving credit facilities | 140 | 120 | 150 |
| Repayments under revolving credit facilities | - | - | (150) |
| Common stock issued | 1,045 | 751 | 662 |
| Common stock dividends paid [2] | (782) | (746) | (704) |
| Other | (1) | 1 | 1 |
| **Net cash provided by (used in) financing activities** | 402 | 126 | (41) |
| **Net change in cash and cash equivalents** | 24 | (2) | (31) |
| **Cash and cash equivalents at January 1** | 207 | 209 | 240 |
| **Cash and cash equivalents at December 31** | $ 231 | $ 207 | $ 209 |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (23) | $ (20) | $ (20) |
| Income taxes, net | 21 | (60) | 8 |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Noncash common stock issuances | $ 22 | $ 22 | $ 24 |
| Common stock dividends declared but not yet paid | 208 | 196 | 188 |

(1) Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries an investing cash flow.

(2) On January 15, April 15, July 15, October 15, 2013, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

On January 15, April 15, July 15, October 15, 2012, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

On January 15, April 15, July 15, October 15, 2011, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

**PG&E Corporation**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2013, 2012, and 2011**
**(in millions)**

| Description | Balance at Beginning of Period | Additions: Charged to Costs and Expenses | Additions: Charged to Other Accounts | Deductions [2] | Balance at End of Period |
|---|---|---|---|---|---|
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2013: | | | | | |
| Allowance for uncollectible accounts [1] | $ 87 | $ 53 | $ - | $ 60 | $ 80 |
| 2012: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 66 | $ - | $ 60 | $ 87 |
| 2011: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 60 | $ - | $ 60 | $ 81 |

[1] Allowance for uncollectible accounts is deducted from “Accounts receivable – Customers.”

[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**Pacific Gas and Electric Company**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2013, 2012, and 2011**
**(in millions)**

| Description | Balance at Beginning of Period | Additions: Charged to Costs and Expenses | Additions: Charged to Other Accounts | Deductions [2] | Balance at End of Period |
|---|---|---|---|---|---|
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2013: | | | | | |
| Allowance for uncollectible accounts [1] | $ 87 | $ 53 | $ - | $ 60 | $ 80 |
| 2012: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 66 | $ - | $ 60 | $ 87 |
| 2011: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 60 | $ - | $ 60 | $ 81 |

[1] Allowance for uncollectible accounts is deducted from “Accounts receivable – Customers.”

[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

EXHIBIT INDEX

| Exhibit Number | Exhibit Description |
|---|---|
| 2.1 | Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1) |
| 2.2 | Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2) |
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of June 19, 2013 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of June 19, 2013 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 3.2) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |

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| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |

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| 4.17 | Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1) |
| 4.20 | First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2) |
| 10.1 | Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.4 | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |

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| 10.5 | | Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9) |
| 10.6 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.11 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.12 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.13 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.14 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5) |
| 10.15 | * | Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.16 | * | Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18) |
| 10.17 | * | Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18) |
| 10.18 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |

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| 10.19 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.20 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.21 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.22 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.23 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.24 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.25 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.26 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.27) |
| 10.27 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.28 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.29 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.30 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.31 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30) |
| 10.32 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |

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| 10.33 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.34 | * | Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36) |
| 10.35 | * | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37) |
| 10.36 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.37 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.38 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.39 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.40 | * | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.41 | * | Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.42 | * | Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2) |
| 10.43 | * | Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.44 | * | Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.45 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.46 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |

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| 10.47 | * | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.48 | * | Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.49 | * | Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.50 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.51 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.52 | * | PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6) |
| 10.53 | * | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.54 | * | PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51) |
| 10.55 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.56 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.57 | * | PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1) |
| 10.58 | * | PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39) |
| 10.59 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.60 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.61 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |

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| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 13 | The following portions of the 2013 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Glossary," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," and "Report of Independent Registered Public Accounting Firm." |
| 21 | Subsidiaries of the Registrant |
| 23 | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | Powers of Attorney |
| 31.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.
** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

**EXHIBIT 12.1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2010** | **2009** |
| **Earnings:** | | | | | |
| Net income | $ 866 | $ 811 | $ 845 | $ 1,121 | $ 1,250 |
| Income tax provision | 326 | 298 | 480 | 574 | 482 |
| Fixed charges | 971 | 891 | 880 | 799 | 817 |
| **Total earnings** | **$ 2,163** | **$ 2,000** | **$ 2,205** | **$ 2,494** | **$ 2,549** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 917 | $ 834 | $ 824 | $ 731 | $ 754 |
| Interest on capital leases | 7 | 9 | 16 | 18 | 19 |
| AFUDC debt | 47 | 48 | 40 | 50 | 44 |
| **Total fixed charges** | **$ 971** | **$ 891** | **$ 880** | **$ 799** | **$ 817** |
| **Ratios of earnings to fixed charges** | **2.23** | **2.24** | **2.51** | **3.12** | **3.12** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2010** | **2009** |
| **Earnings:** | | | | | |
| Net income | $ 866 | $ 811 | $ 845 | $ 1,121 | $ 1,250 |
| Income tax provision | 326 | 298 | 480 | 574 | 482 |
| Fixed charges | 971 | 891 | 880 | 799 | 817 |
| **Total earnings** | **$ 2,163** | **$ 2,000** | **$ 2,205** | **$ 2,494** | **$ 2,549** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 917 | $ 834 | $ 824 | $ 731 | $ 754 |
| Interest on capital leases | 7 | 9 | 16 | 18 | 19 |
| AFUDC debt | 47 | 48 | 40 | 50 | 44 |
| **Total fixed charges** | **$ 971** | **$ 891** | **$ 880** | **$ 799** | **$ 817** |
| **Preferred stock dividends:** | | | | | |
| Tax deductible dividends | $ 9 | $ 9 | $ 9 | $ 9 | $ 9 |
| Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements | 7 | 7 | 8 | 7 | 7 |
| **Total preferred stock dividends** | **16** | **16** | **17** | **16** | **16** |
| **Total combined fixed charges and preferred stock dividends** | **$ 987** | **$ 907** | **$ 897** | **$ 815** | **$ 833** |
| **Ratios of earnings to combined fixed charges and preferred stock dividends** | **2.19** | **2.21** | **2.46** | **3.06** | **3.06** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.3**
**PG&E CORPORATION**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2010** | **2009** |
| **Earnings:** | | | | | |
| Net income | $ 828 | $ 830 | $ 858 | $ 1,113 | $ 1,234 |
| Income tax provision | 268 | 237 | 440 | 547 | 460 |
| Fixed charges | 1,012 | 931 | 919 | 850 | 877 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | (16) | (15) | (17) | (16) | (16) |
| **Total earnings** | **$ 2,092** | **$ 1,983** | **$ 2,200** | **$ 2,494** | **$ 2,555** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 942 | $ 859 | $ 846 | $ 766 | $ 798 |
| Interest on capital leases | 7 | 9 | 16 | 18 | 19 |
| AFUDC debt | 47 | 48 | 40 | 50 | 44 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated | 16 | 15 | 17 | 16 | 16 |
| **Total fixed charges** | **$ 1,012** | **$ 931** | **$ 919** | **$ 850** | **$ 877** |
| **Ratios of earnings to fixed charges** | **2.07** | **2.13** | **2.39** | **2.93** | **2.91** |

Note:
For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

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## SELECTED FINANCIAL DATA

| (in millions, except per share amounts) | 2013 | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 15,598 | $ 15,040 | $ 14,956 | $ 13,841 | $ 13,399 |
| Operating income | 1,762 | 1,693 | 1,942 | 2,308 | 2,299 |
| Income from continuing operations | 828 | 830 | 858 | 1,113 | 1,234 |
| Earnings per common share from continuing operations, basic | 1.83 | 1.92 | 2.10 | 2.86 | 3.25 |
| Earnings per common share from continuing operations, diluted | 1.83 | 1.92 | 2.10 | 2.82 | 3.20 |
| Dividends declared per common share (1) | 1.82 | 1.82 | 1.82 | 1.82 | 1.68 |
| **At Year-End** | | | | | |
| Common stock price per share | $ 40.28 | $ 40.18 | $ 41.22 | $ 47.84 | $ 44.65 |
| Total assets | 55,605 | 52,449 | 49,750 | 46,025 | 42,945 |
| Long-term debt (excluding current portion) | 12,717 | 12,517 | 11,766 | 10,906 | 10,381 |
| Capital lease obligations (excluding current portion) (2) | 90 | 113 | 212 | 248 | 282 |
| Energy recovery bonds (excluding current portion) (3) | - | - | - | 423 | 827 |
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 15,593 | $ 15,035 | $ 14,951 | $ 13,840 | $ 13,399 |
| Operating income | 1,790 | 1,695 | 1,944 | 2,314 | 2,302 |
| Income available for common stock | 852 | 797 | 831 | 1,107 | 1,236 |
| **At Year-End** | | | | | |
| Total assets | 55,049 | 51,923 | 49,242 | 45,679 | 42,709 |
| Long-term debt (excluding current portion) | 12,717 | 12,167 | 11,417 | 10,557 | 10,033 |
| Capital lease obligations (excluding current portion) (2) | 90 | 113 | 212 | 248 | 282 |
| Energy recovery bonds (excluding current portion) (3) | - | - | - | 423 | 827 |

(1) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources – Dividends" within "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 of the Notes to the Consolidated Financial Statements.

(2) The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

(3) The energy recovery bonds matured in December 2012.

## GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2013 Annual Report | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2013, including the information incorporated by reference into the report |
| AFUDC | Allowance for Funds Used During Construction |
| ALJ | administrative law judge |
| ARO | Asset retirement obligation |
| ASU | accounting standards update |
| CAISO | California Independent System Operator |
| CARB | California Air Resources Board |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| EPA | Environmental Protection Agency |
| EPS | earnings per common share |
| FERC | Federal Energy Regulatory Commission |
| GAAP | generally accepted accounting principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| IRS | Internal Revenue Service |
| LTIP | long term incentive plan |
| MGP | manufactured gas plant |
| NEIL | Nuclear Electric Insurance Limited |
| NRC | Nuclear Regulatory Commission |
| ORA | Officer of Ratepayer Advocates |
| OSC | CPUC Order to Show Cause |
| PSEP | pipeline safety enhancement plan |
| QF(s) | Qualified facilities |
| Regional Board | California Regional Water Quality Control Board, Lahontan Region |
| REITS | Global real estate investment trust |
| RSU(s) | restricted stock unit |
| ROE | return on equity |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount of revenue that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs (depreciation, tax, and financing expenses) of providing utility services. The primary CPUC proceedings are the GRC and the GT&S rate case which generally occur every few years and result in revenue requirements that are set for multi-year periods. The CPUC also periodically conducts a cost of capital proceeding, where it determines the capital structure the Utility must maintain (i.e., the relative weightings of common equity, long-term debt, and preferred equity) and authorizes the Utility to earn a specific rate of return on each capital component, including equity. The authorized revenue requirements the CPUC sets in the GRC and GT&S rate cases are set at levels to provide the Utility an opportunity to earn its authorized rates of return on its "rate base" – the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers. The primary FERC proceeding is the electric TO rate case which generally occurs on an annual basis. The rate of return for the Utility's FERC jurisdictional assets is embedded in revenues authorized in the TO rate cases.

The Utility's ability to recover its GRC revenue requirements does not depend on the volume of the Utility's sales of electricity and natural gas services. This decoupling of revenues and sales eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand. The Utility's ability to recover a portion of its GT&S revenue requirements depends on the volume of natural gas transported as well as the use of its storage facilities. The Utility's ability to recover its electric transmission-related revenue requirements depends on the volume of electricity sales.

The Utility's revenue requirements are set based on forecast costs. Differences in the amount or timing between forecast costs and actual costs can occur for numerous reasons, including unanticipated costs related to storms, outages, catastrophic events, or to comply with new legislation, regulations, or orders; or third-party claims that are not recoverable through insurance. Generally, differences between actual costs and forecast costs could affect the Utility's ability to earn its authorized return (referred to as "activities impacting earnings" below). However, for certain core operating costs, such as costs associated with pension and other employee benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "cost recovery activities" below). The Utility also collects additional revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose programs, such as demand response and customer energy efficiency. Therefore, although the timing and amount of these costs can impact the Utility's revenue, these costs generally do not impact net income (included in "cost recovery activities" below).

There may be some types of costs that the CPUC has determined will not be recoverable through rates or for which the Utility does not seek recovery, such as certain pipeline-related costs and fines associated with the Utility's natural gas transmission system. The CPUC could also disallow recovery of costs that it finds were not prudently or reasonably incurred. The timing and amount of the unrecoverable or disallowed costs can materially impact the Utility's revenue and net income, as described more fully below.

This is a combined annual report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

**Sum mary of Changes in Net Income and Earnings per Share**

PG&E Corporation's net income available for common shareholders for 2013 was $814 million, or $1.83 per share, as compared to $816 million, or $1.92 per share, for 2012. Operating results have continued to be materially affected by costs the Utility has incurred to improve the safety and reliability of its natural gas operations that are not recoverable through rates. These unrecovered costs have increased the Utility's equity needs which PG&E Corporation has funded through equity issuances that have materially diluted PG&E Corporation's EPS.

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS for the year ended December 31, 2013 compared to the prior year. (See "Results of Operations" and "Natural Gas Matters" below for additional information.)

| **(in millions, except per share amounts)** | **Earnings** | **EPS (Diluted)** |
|---|---|---|
| **Income Available for Common Shareholders - 2012** | $ 816 | $ 1.92 |
| Natural gas matters [1] | 96 | 0.27 |
| Growth in rate base earnings [2] | 87 | 0.19 |
| Environmental-related costs [3] | 59 | 0.14 |
| Reduction in authorized cost of capital [4] | (166) | (0.37) |
| Impact of capital spending over authorized [5] | (24) | (0.06) |
| Uneconomic project and lease termination [6] | (11) | (0.03) |
| Gas transmission revenues | (9) | (0.02) |
| Increase in shares outstanding [7] | - | (0.15) |
| Other | (34) | (0.06) |
| **Income Available for Common Shareholders - 2013** | **$ 814** | **$ 1.83** |

[1] The Utility incurred net costs and capital charges related to natural gas matters of $645 million and $812 million, pre-tax, during 2013 and 2012, respectively. These amounts are not recoverable through rates. See "Operating and Maintenance" below.

[2] Represents the impact of the increase in rate base as authorized in various rate cases during 2013 as compared to 2012 .

[3] Environmental-related costs were lower in 2013 compared to 2012 when the Utility incurred a significant charge for environmental remediation associated with the Hinkley natural gas compressor site.

[4] Reflects the lower cost of capital authorized in the 2013 Cost of Capital proceeding. The CPUC authorized the Utility to earn a ROE of 10.40% (compared to 11.35% previously authorized) and adjusted its cost of debt beginning on January 1, 2013.

[5] Represents the incremental interest and depreciation expense associated with capital expenditures that exceed the current authorized levels.

[6] Represents the expenses incurred in 2013 for terminated projects and leases, compared to 2012.

[7] Represents the impact of a higher number of weighted average shares outstanding during 2013, compared to 2012. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including expenses related to natural gas matters. This has no dollar impact on earnings.

**Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows**

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materially affected by several factors, including the timing and outcome of CPUC ratemaking proceedings, the ultimate amount of costs the Utility will continue to incur to improve the safety and reliability of its natural gas operations, the outcome of the pending investigations that commenced following the San Bruno accident including the ultimate amount of fines the Utility will be required to pay, and the timing and amount of the Utility's financing needs.

- *The Timing and Outcome of Ratemaking Proceedings* . The majority of the Utility's revenue requirements for the next several years will be determined by the outcomes of the 2014 GRC and the 2015 GT&S rate case. In the 2014 GRC, the Utility is seeking an increase in its 2014 revenue requirements of $1.16 billion over the comparable revenues for 2013 that were previously authorized, as well as attrition increases for 2015 and 2016. The CPUC's ORA has recommended that the CPUC approve a 2014 revenue requirement that is lower than the amount authorized for 2013. A proposed decision is anticipated in the first quarter of 2014. (See "2014 General Rate Case" below.) In the 2015 GT&S rate case, the Utility is seeking an increase in its 2015 revenue requirements of $555 million over the comparable revenues for 2014 that were previously authorized, as well as attrition increases for 2016 and 2017. The Utility has requested that the CPUC issue a final decision by the end of 2014. (See "2015 Gas Transmission and Storage Rate Case" below.) The outcome of these ratemaking proceedings can be affected by many factors, including general economic conditions, the level of customer rates, regulatory policies, and political considerations.

- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* Net income is negatively affected when the authorized revenues are not sufficient for the Utility to recover the costs it actually incurs to provide utility services. The Utility forecasts that it will incur total pipeline-related expenses ranging from $350 million to $450 million in 2014 that will not be recoverable through rates. These amounts include costs to perform work under the Utility's PSEP that were disallowed by the CPUC, as well as costs related to the Utility's multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way and other gas-related work, and legal and other expenses. The Utility could record additional charges for PSEP capital to the extent the Utility's costs are higher than expected or if additional costs are disallowed by the CPUC. (See "Disallowed Capital Costs" below.) The Utility's ability to recover pipeline-related expenses beginning in 2015 also will be affected by the outcome of the 2015 GT&S rate case. Differences between the amount or timing of the Utility's actual costs and forecasted or authorized amounts may affect the Utility's ability to earn its authorized ROE.

- *The Outcome of Pending Investigations and Enforcement Matters.* Three CPUC investigations are still pending against the Utility related to its natural gas operations and the San Bruno accident. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.95 billion of non-recoverable costs. If the SED's penalty recommendation is adopted, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about $4.5 billion. (See "Pending CPUC Investigations" below.) In addition, the CPUC and the SED may impose fines or take enforcement action with respect to the Utility's self-reports of noncompliance with certain natural gas safety regulations. (See "CPUC Enforcement Matters" below.) The Utility may be required to pay additional civil or criminal penalties or incur other costs, depending on the outcome of the pending federal criminal investigation of the San Bruno accident. (See "Criminal Investigation" below.)

- *The Amount and Timing of the Utility's Financing Needs* . PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. Future financing needs will be affected by various factors, including the timing and amount of capital expenditures and operating expenses, the amount of costs related to natural gas matters that are not recoverable through rates, and other factors described in "Liquidity and Financial Resources" below. PG&E Corporation forecasts that it will issue a material amount of equity in 2014, primarily to support the Utility's 2014 capital expenditures (which are forecasted to range from $5 billion to $6 billion) and to fund unrecovered costs. Depending on the outcome of the pending investigations, PG&E Corporation may be required to issue additional common stock to fund its equity contributions as the Utility pays fines and incurs additional unrecoverable gas safety-related costs. These additional issuances could have a material dilutive effect on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by changes in their respective credit ratings, the outcome of natural gas matters, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see the section entitled "Risk Factors" below. In addition, this 2013 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Cautionary Language Regarding Forward Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## RE SULTS OF OPERATIONS

### PG&E Corporation

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The table below provides a summary of consolidated net income (loss) for 2013, 2012 and 2011:

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Consolidated Total | $ 814 | $ 816 | $ 844 |
| PG&E Corporation | (38) | 19 | 13 |
| Utility | 852 | 797 | 831 |

PG&E Corporation's net income consists primarily of operating and maintenance expense, interest expense on long-term debt, other income from investments, and income taxes. In 2013, PG&E Corporation's operating results were primarily impacted by an impairment loss resulting from investments unrelated to PG&E Corporation's core operations with no similar activity in 2012 and by an increase in charitable contributions. There were no material changes to PG&E Corporation's operating results in 2012 compared to 2011.

### Utility

The table below details certain items from the Utility's accompanying Consolidated Statements of Income for 2013, 2012, and 2011. The presentation below separately identifies activities that impact earnings and cost recovery activities that do not impact earnings.

Activities that impact earnings (net income) primarily include revenues authorized by the CPUC and FERC in the various rate cases that are designed to recover the Utility's costs to own and operate its assets and provide it with an opportunity to earn its authorized rate of return on its rate base. Expenses that impact earnings include costs in excess of amounts authorized and costs for which the Utility does not seek recovery. (See "Utility Activities Impacting Earnings" below.) Activities that do not impact earnings include revenues collected to recover certain costs that the Utility is authorized to pass on to customers, including costs to purchase electricity and natural gas, as well as costs to fund public purpose programs. They also include revenues authorized in various rate cases that are designated for a specific purpose such as the payment of pension costs. (See "Utility Cost Recovery Activities" below.)

| | 2013 | | | 2012 | | | 2011 | | |
|---|---|---|---|---|---|---|---|---|---|
| (in millions) | Earning Activities | Cost Recovery Activities | Total Utility | Earning Activities | Cost Recovery Activities | Total Utility | Earning Activities | Cost Recovery Activities | Total Utility |
| Electric operating revenues | $ 6,465 | $ 6,024 | $ 12,489 | $ 6,414 | $ 5,600 | $ 12,014 | $ 6,150 | $ 5,451 | $ 11,601 |
| Natural gas operating revenues | 1,776 | 1,328 | 3,104 | 1,772 | 1,249 | 3,021 | 1,696 | 1,654 | 3,350 |
| **Total operating revenues** | **8,241** | **7,352** | **15,593** | **8,186** | **6,849** | **15,035** | **7,846** | **7,105** | **14,951** |
| Cost of electricity | - | 5,016 | 5,016 | - | 4,162 | 4,162 | - | 4,016 | 4,016 |
| Cost of natural gas | - | 968 | 968 | - | 861 | 861 | - | 1,317 | 1,317 |
| Operating and maintenance | 4,374 | 1,368 | 5,742 | 4,563 | 1,482 | 6,045 | 4,087 | 1,372 | 5,459 |
| Depreciation, amortization, and decommissioning | 2,077 | - | 2,077 | 1,928 | 344 | 2,272 | 1,815 | 400 | 2,215 |
| **Total operating expenses** | **6,451** | **7,352** | **13,803** | **6,491** | **6,849** | **13,340** | **5,902** | **7,105** | **13,007** |
| **Operating income** | **1,790** | **-** | **1,790** | **1,695** | **-** | **1,695** | **1,944** | **-** | **1,944** |
| Interest income (1) | | | 8 | | | 6 | | | 5 |
| Interest expense (1) | | | (690) | | | (680) | | | (677) |
| Other income, net (1) | | | 84 | | | 88 | | | 53 |
| Income before income taxes | | | 1,192 | | | 1,109 | | | 1,325 |
| Income tax provision (1) | | | 326 | | | 298 | | | 480 |
| Net income | | | 866 | | | 811 | | | 845 |

| | | | |
|---|---|---|---|
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 852** | **$ 797** | **$ 831** |

(1) Items represent activities that impact earnings for 2013, 2012, and 2011.

**Utility Activities Impacting Earnings**

The following discussion presents the Utility's operating results for activities impacting earnings for 2013, 2012, and 2011.

*Operating Revenues*

The Utility's electric and natural gas operating revenues increased by $55 million, or 1%, in 2013 compared to 2012, primarily due to an increase of $294 million as authorized in various rate cases, partially offset by a decrease in revenues of $196 million as a result of the lower return authorized in the 2013 Cost of Capital proceeding.

The Utility's electric and natural gas operating revenues increased by $340 million, or 4%, in 2012 compared to 2011 primarily due to an increase in revenues authorized in various rate cases and increases in natural gas storage revenues.

*Operating and Maintenance*

The Utility's operating and maintenance expenses decreased by $189 million, or 4%, in 2013 compared to 2012, primarily due to decreases of $167 million for net costs incurred in connection with natural gas matters (see table below) and $88 million for environmental remediation costs associated with a significant charge in 2012 for the Hinkley natural gas compressor station site. These costs were partially offset by increases in other expenses that were not material. In each of 2013 and 2012, the Utility incurred expenses that were approximately $250 million higher than the level of authorized revenue requirements to improve the safety and reliability of its operations that will not be recovered in rates.

The Utility's operating and maintenance expenses increased by $476 million, or 12%, in 2012 compared to 2011, primarily due to costs incurred to improve the safety and reliability of electric and natural gas operations that were approximately $250 million higher than amounts assumed under the 2011 rate cases. The remaining increase was primarily attributable to an increase of $73 million for net costs incurred in connection with natural gas matters (see table below), and a $56 million charge related to employee operational performance incentives.

The following table provides a summary of the Utility's costs associated with natural gas matters that are not recoverable through rates:

| **(in millions)** | **2013** | **2012** | **2011** |
|---|---|---|---|
| Pipeline-related expenses [1] [2] | $ 387 | $ 477 | $ 483 |
| Disallowed capital | 196 | 353 | - |
| Accrued fines | 22 | 17 | 200 |
| Third-party liability claims | 110 | 80 | 155 |
| Insurance recoveries | (70) | (185) | (99) |
| Contribution to City of San Bruno | - | 70 | - |
| **Total natural gas matters** | **$ 645** | **$ 812** | **$ 739** |

(1) Includes $137 million, $268 million, and $331 million for work performed under the Utility's PSEP in 2013, 2012, and 2011, respectively.

(2) The decrease for 2013 reflects amounts that were authorized for recovery in the CPUC's PSEP December 2012 decision as well as lower legal and other expenses in 2013.

Pipeline-related expenses include costs to validate safe operating pressures, conduct strength testing, and perform other work associated with the Utility's PSEP; costs related to the Utility's multi-year effort to identify and remove encroachments (e.g. building structures and vegetation overgrowth) from transmission pipeline rights-of-way, and costs to improve the integrity of transmission pipelines and to perform other gas-related work; and legal and other expenses. In 2013, the Utility completed its "centerline" mapping survey of its entire gas transmission system to locate, mark, and map the center of all transmission pipelines. The Utility recorded charges of $196 million and $353 million in 2013 and 2012, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. The additional charge in 2013 primarily reflects a change in project portfolio involving higher unit costs to replace pipelines than originally forecast. (See "Natural Gas Matters – Disallowed Capital Costs" below.)

The Utility recorded charges of $22 million and $17 million in 2013 and 2012, respectively, for fines imposed on the Utility by the CPUC and SED in connection with various self-reported violations and other enforcement matters. The Utility accrued $200 million in 2011 as the minimum amount of fines deemed probable that the Utility will pay to the State General Fund in connection with the three pending CPUC investigations. (See "Natural Gas Matters – Pending CPUC Investigations" below.)

The Utility has settled the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury, property damage, and other relief, following the San Bruno accident. The Utility has recorded cumulative charges of $565 million for third-party claims related to the San Bruno accident, reflecting its best estimate of probable loss. These costs were partially offset by cumulative insurance recoveries of $354 million. Although the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses of $86 million) will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased by $149 million, or 8%, in 2013 compared to 2012, and by $113 million, or 6%, in 2012 compared to 2011, primarily due to the impact of capital additions.

*Interest Income, Interest Expense, and Other Income, Net*

There were no material changes to interest income, interest expense, and other income, net for the periods presented.

*Income Tax Provision*

The Utility's income tax provision increased by $28 million, or 9%, in 2013 compared to 2012. The effective tax rates were 27% in both 2013 and 2012.

The Utility's income tax provision decreased by $182 million, or 38%, in 2012 compared to 2011. The effective tax rates were 27% and 36% for 2012 and 2011, respectively. The effective tax rate decreased primarily due to lower state and federal taxes for non-tax deductible penalties related to natural gas matters.

The differences between the Utility's income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations for 2013, 2012, and 2011 were as follows:

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| Federal statutory income tax rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) | (2.2) | (3.0) | 1.6 |
| Effect of regulatory treatment of fixed asset differences | (3.8) | (3.9) | (4.2) |
| Tax credits | (0.4) | (0.6) | (0.5) |
| Benefit of loss carryback | (1.0) | (0.4) | (2.1) |
| Non deductible penalties | 0.7 | 0.5 | 6.3 |
| Other, net | (0.9) | (0.8) | 0.1 |
| **Effective tax rate** | **27.4%** | **26.8%** | **36.2%** |

**Utility Cost Recovery Activities**

*Cost of Electricity*

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements.) The volume of power purchased by the Utility is driven by customer demand, the availability of the Utility's own generation facilities, and the cost effectiveness of each source of electricity. Additionally, the cost of electricity is impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with California legislative and regulatory requirements, and by costs associated with complying with California's GHG laws.

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Cost of purchased power | $ 4,696 | $ 3,873 | $ 3,719 |
| Fuel used in own generation facilities | 320 | 289 | 297 |
| **Total cost of electricity** | **$ 5,016** | **$ 4,162** | **$ 4,016** |
| Average cost of purchased power per kWh | $ 0.094 | $ 0.079 | $ 0.089 |
| Total purchased power (in millions of kWh) | **49,941** | **48,933** | **41,958** |

*Cost of Gas*

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements.) The Utility's future cost of natural gas will be affected by the market price of natural gas, changes in the cost of storage and transportation, changes in customer demand, and by costs associated with complying with California's GHG laws.

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Cost of natural gas sold | $ 807 | $ 676 | $ 1,136 |
| Transportation cost of natural gas sold | 161 | 185 | 181 |
| **Total cost of natural gas** | **$ 968** | **$ 861** | **$ 1,317** |
| Average cost per Mcf of natural gas sold | $ 3.54 | $ 2.91 | $ 4.49 |
| Total natural gas sold (in millions of Mcf) (1) | 228 | 232 | 253 |

(1) One thousand cubic feet

*Operating Expenses*

The Utility's operating expenses also include certain recoverable costs that the Utility is required to incur as part of its operations and include public purpose programs, pension, and other continuous business expenses. Additionally, operating expenses in 2012 and 2011 include the amortization of energy recovery bonds regulatory asset which fully amortized in 2012. If the Utility were to spend over authorized amounts, these expenses could have an impact to earnings.

## LI QUIDITY AND FINANCIAL RESOURCES

### Overview

The Utility's ability to fund operations and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal load, volatility in energy commodity costs, collateral requirements related to price risk management activities, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and long-term financings, among other factors. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The Utility has short-term borrowing authority of $4.0 billion, including $500 million that is restricted to certain contingencies.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, and pay dividends primarily depends on PG&E Corporation's access to the capital and credit markets and the level of cash distributions received from the Utility. PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation's stock issuances used to fund Utility equity needs attributable to unrecoverable costs and penalties have had and will continue to have a dilutive effective on PG&E Corporation's EPS. PG&E Corporation also may use draws under its revolving credit facility or issuances under its commercial paper program to occasionally fund equity contributions on an interim basis.

PG&E Corporation and the Utility have $889 million of long-term debt maturing within the next 6 months. PG&E Corporation and the Utility plan to repay this debt with capital market financings.

Further, given the Utility's significant ongoing capital expenditures, the Utility will continue to need equity contributions from PG&E Corporation to maintain its authorized capital structure. The Utility's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters, incremental work to improve safety and reliability of electric and gas operations in excess of authorized revenue requirements, and environmental remediation costs. The Utility's equity needs would also increase to the extent it is required to pay fines or penalties in connection with pending investigations. (See "Natural Gas Matters" below.)

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of the pending investigations related to natural gas matters and the San Bruno accident. PG&E Corporation's and the Utility's credit ratings may affect their access to the credit and capital markets and their respective financing costs in those markets. Credit rating downgrades may increase the cost of short-term borrowing, including PG&E Corporation's and the Utility's commercial paper, as well as the costs associated with their respective credit facilities, and long-term debt.

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. The following table summarizes PG&E Corporation's and the Utility's cash positions:

| | **December 31,** | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| PG&E Corporation | $ 231 | $ 207 |
| Utility | 65 | 194 |
| **Total consolidated cash and cash equivalents** | **$ 296** | **$ 401** |

In addition to these cash and cash equivalents, PG&E Corporation and the Utility hold restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See Note 12 of the Notes to the Consolidated Financial Statements.)

**Revolving Credit Facilities and Commercial Paper Programs**

In April 2013, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from May 31, 2016 to April 1, 2018. These agreements contain substantially similar terms as the original 2011 credit agreements.

In January 2014, PG&E Corporation established a new commercial paper program, the borrowings of which will be used primarily to cover fluctuations in cash flow requirements. PG&E Corporation will treat the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and the Utility's commercial paper program at December 31, 2013:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Borrowings | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|---|
| PG&E Corporation | April 2018 | $ 300[1] | $ - | $ 260 | $ - | $ 40 |
| Utility | April 2018 | 3,000[2] | 79 | - | 914[3] | 2,007[3] |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 79** | **$ 260** | **$ 914** | **$ 2,047** |

[1] Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
[2] Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
[3] The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2013, the average outstanding borrowings under PG&E Corporation's revolving credit facility were $214 million and the maximum outstanding balance during the year was $260 million. For 2013, the Utility's average outstanding commercial paper balance was $542 million and the maximum outstanding balance during the year was $1.1 billion. The Utility did not borrow under its credit facility in 2013.

The revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. At December 31, 2013, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

**2013 Financings**

***Utility***

The following table summarizes long-term debt issuances in 2013:

| (in millions) | Issue Date | Amount |
|---|---|---|
| **Senior Notes** | | |
| 3.25%, due 2023 | June 14 | $ 375 |
| 4.60%, due 2043 | June 14 | 375 |
| 3.85%, due 2023 | November 12 | 300 |
| 5.125%, due 2043 | November 12 | 500 |
| **Total debt issuances in 2013** | | **$ 1,550** |

The net proceeds from the issuance of Utility senior notes in 2013 were used to fund maturing debt, to repurchase and extinguish $461 million principal amount, net of $15 million of premiums and $6 million of accrued interest, of the Utility's outstanding 4.80% Senior Notes due March 1, 2014, fund capital expenditures, and for general corporate purposes.

The Utility also received cash contributions of $1.1 billion from PG&E Corporation during 2013 to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC.

***PG&E Corporation***

In May 2013, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $400 million. As of December 31, 2013, PG&E Corporation had sold common stock having an aggregate gross sales price of $395 million and had the ability to issue an additional $5 million of its common stock under this agreement. During 2013, PG&E Corporation paid commissions of $3 million under this agreement. PG&E Corporation terminated this agreement in January 2014 and intends to enter into a new equity distribution agreement providing for the sale of PG&E Corporation's common stock having an aggregate gross sales price of $500 million.

During 2013, PG&E Corporation issued 26 million shares of its common stock for aggregate net cash proceeds of $1,045 million in the following transactions:

- 7 million shares were sold in an underwritten public offering for cash proceeds of $300 million, net of fees and commissions;
- 8 million shares that were issued for cash proceeds of $290 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and
- 11 million shares were sold for cash proceeds of $455 million, net of commissions paid of $4 million, under equity distribution agreements.

The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. For the year ended December 31, 2013, PG&E Corporation made equity contributions to the Utility of $1.1 billion. PG&E Corporation forecasts that it will need to continue to issue additional common stock to fund the Utility's equity needs.

**Dividends**

The Board of Directors of PG&E Corporation and the Utility have each adopted a common stock dividend policy that is designed to meet the following three objectives:

- *Comparability* : Pay a dividend competitive with the securities of comparable companies based on payout ratio (the proportion of earnings paid out as dividends) and, with respect to PG&E Corporation, yield (i.e., dividend per share divided by share price);
- *Flexibility:* Allow sufficient cash to pay a dividend and to fund investments while avoiding having to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- *Sustainability:* Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

Each Board of Directors retains authority to change the common stock dividend rate at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors. In addition, before declaring a dividend, the CPUC requires that the PG&E Corporation Board of Directors give first priority to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The Boards of Directors must also consider the CPUC requirement that the Utility maintain, on average, its CPUC-authorized capital structure including a 52% equity component.

The Board of Directors of PG&E Corporation declared dividends of $0.455 per share for each of the quarters of 2013, 2012, and 2011, for annual dividends of $1.82 per share.

The following table summarizes PG&E Corporation's and the Utility's dividends paid:

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| **PG&E Corporation:** | | | |
| Common stock dividends paid | $ 782 | $ 746 | $ 704 |
| Common stock dividends reinvested in Dividend Reinvestment and Stock Purchase Plan | 22 | 22 | 24 |
| **Utility:** | | | |
| Common stock dividends paid | $ 716 | $ 716 | $ 716 |
| Preferred stock dividends paid | 14 | 14 | 14 |

In December 2013, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $208 million, of which $202 million was paid in January 2014 to shareholders of record on December 31, 2013.

In December 2013, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable in February 2014, to shareholders of record on January 31, 2014.

As the Utility focuses on improving the safety and reliability of its natural gas and electric operations, and subject to the outcome of the matters described under "Natural Gas Matters" below, PG&E Corporation expects that its Board will continue to maintain the current quarterly common stock dividend.

**Utility**

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for 2013, 2012, and 2011 were as follows:

| **(in millions)** | **2013** | **2012** | **2011** |
|---|---|---|---|
| Net income | $ 866 | $ 811 | $ 845 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,077 | 2,272 | 2,215 |
| Allowance for equity funds used during construction | (101) | (107) | (87) |
| Deferred income taxes and tax credits, net | 1,103 | 684 | 582 |
| PSEP disallowed capital expenditures | 196 | 353 | - |
| Other | 299 | 236 | 289 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (152) | (40) | (227) |
| Inventories | (10) | (24) | (63) |
| Accounts payable | 99 | (26) | 51 |
| Income taxes receivable/payable | (377) | (50) | (192) |
| Other current assets and liabilities | (404) | 272 | 36 |
| Regulatory assets, liabilities, and balancing accounts, net | (202) | 291 | (100) |
| Other noncurrent assets and liabilities | 22 | 256 | 414 |
| **Net cash provided by operating activities** | **$ 3,416** | **$ 4,928** | **$ 3,763** |

During 2013, net cash provided by operating activities decreased by $1.5 billion as compared to 2012 when the Utility collected $460 million from customers related to the energy recovery bonds which matured at the end of 2012. In addition, in 2013, the amount of cash collateral returned to the Utility by third parties was $243 million lower than in 2012, the settlement payments the Utility received from the U.S Treasury related to the Utility's spent nuclear fuel disposal costs was $221 million lower, net of legal fees, than the Utility received in 2012, and the Utility's tax payments were $236 million higher than in 2012. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

During 2012, net cash provided by operating activities increased by $1.2 billion compared to 2011 when the Utility's net collateral payments were $352 million higher. Also, in 2012, the Utility received settlement payments of $250 million, net of legal fees, from the U.S. Treasury related to the Utility's spent nuclear fuel disposal costs and made tax payments that were $224 million lower than in 2011. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and outcome of ratemaking proceedings, including the 2014 GRC and 2015 GT&S rate cases;
- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments;
- the timing and amount of insurance recoveries related to third party claims;
- the timing and amount of fines or penalties that may be imposed, as well as any costs associated with remedial actions the Utility may be required to implement;
- the timing and amount of costs the Utility incurs, but does not recover, to improve the safety and reliability of its natural gas system (see "Operating and Maintenance" above and "Natural Gas Matters" below); and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of interest on these claims that the Utility will be required to pay (see Note 12 of the Notes to the Consolidated Financial Statements).

***Investing Activities***

The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. The amount and timing of the Utility's capital expenditures is affected by many factors such as the occurrence of storms and other events causing outages or damages to the Utility's infrastructure. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's cash flows from investing activities for 2013, 2012, and 2011 were as follows:

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Capital expenditures | $ (5,207) | $ (4,624) | $ (4,038) |
| Decrease in restricted cash | 29 | 50 | 200 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,619 | 1,133 | 1,928 |
| Purchases of nuclear decommissioning trust investments | (1,604) | (1,189) | (1,963) |
| Other | 21 | 16 | 14 |
| **Net cash used in investing activities** | **$ (5,142)** | **$ (4,614)** | **$ (3,859)** |

Net cash used in investing activities increased by $528 million in 2013 compared to 2012. This increase was due to an increase of $583 million in capital expenditures, partially offset by net proceeds associated with sales of nuclear decommissioning trust investments in 2013 as compared to net purchases of nuclear decommissioning trust investments in 2012.

Net cash used in investing activities increased by $755 million in 2012 compared to 2011. This increase was primarily due to an increase of $586 million in capital expenditures and a reduction in restricted cash released for resolved Chapter 11 disputed claims of $150 million.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility forecasts that it will incur between $5 billion and $6 billion in capital expenditures for 2014. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases. The Utility's ability to invest in its electric and natural gas systems and develop new generation facilities is subject to many risks, including risks related to securing adequate and reasonably priced financing, obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards.

***Financing Activities***

The Utility's cash flows from financing activities for 2013, 2012, and 2011 were as follows:

| **(in millions)** | **2013** | **2012** | **2011** |
|---|---|---|---|
| Borrowings under revolving credit facilities | $ - | $ - | $ 208 |
| Repayments under revolving credit facilities | - | - | (208) |
| Net issuances (repayments) of commercial paper, net of discount of $2 in 2013, $3 in 2012, and $4 in 2011 | 542 | (1,021) | 782 |
| Proceeds from issuance of short-term debt | - | - | 250 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $18 in 2013, $13 in 2012, and $8 in 2011 | 1,532 | 1,137 | 792 |
| Short-term debt matured | - | (250) | (250) |
| Long-term debt matured or repurchased | (861) | (50) | (700) |
| Energy recovery bonds matured | - | (423) | (404) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution | 1,140 | 885 | 555 |
| Other | (26) | 28 | 54 |
| **Net cash provided by (used in) financing activities** | **$ 1,597** | **$ (424)** | **$ 349** |

In 2013, net cash provided by financing activities increased by $2.0 billion compared to the same period in 2012. In 2012, net cash provided by financing activities decreased by $773 million compared to 2011. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

**PG&E Corporation**

PG&E Corporation affiliates hold four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that are considered VIEs. Under these agreements, PG&E Corporation has made cumulative lease payments and investment contributions of $362 million and received $275 million in benefits and customer payments from 2010 to 2013. PG&E Corporation has no material remaining commitment to fund these agreements. Lease payments, investment contributions, benefits, and customer payments received are included in cash flows from operating and investing activities within the Consolidated Statements of Cash Flows.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the years ended December 31, 2013, 2012, and 2011: dividend payments, common stock issuances, borrowings and repayments under its revolving credit facility, and transactions between PG&E Corporation and the Utility.

**CO NTRACTUAL COMMITMENTS**

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2013:

| | Payment due by period | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **Less Than 1 Year** | **1-3 Years** | **3-5 Years** | **More Than 5 Years** | **Total** |
| **Contractual Commitments:** | | | | | |
| **Utility** | | | | | |
| Long-term debt [(1)] : | | | | | |
| Fixed rate obligations | $ 1,181 | $ 1,258 | $ 2,718 | $ 18,708 | $ 23,865 |
| Variable rate obligations | 2 | 326 | 651 | 211 | 1,190 |
| Purchase obligations [(2)] : | | | | | |
| Power purchase agreements: | | | | | |
| Qualifying facilities | 913 | 1,294 | 856 | 1,614 | 4,677 |
| Renewable energy (other than QF) | 1,906 | 4,211 | 4,066 | 30,242 | 40,425 |
| Other power purchase agreements | 829 | 1,492 | 1,324 | 2,984 | 6,629 |
| Natural gas supply, transportation, and storage | 727 | 348 | 216 | 756 | 2,047 |
| Nuclear fuel agreements | 145 | 308 | 280 | 647 | 1,380 |
| Pension and other benefits [(3)] | 398 | 796 | 796 | 398 | 2,388 |
| Capital lease obligations [(2)] | 27 | 46 | 30 | 8 | 111 |
| Operating leases [(2)] | 42 | 71 | 51 | 193 | 357 |
| Preferred dividends [(4)] | 14 | 28 | 28 | - | 70 |
| **PG&E Corporation** | | | | | |
| Long-term debt [(1)] : | | | | | |
| Fixed rate obligations | 355 | - | - | - | 355 |
| **Total** | **6,539** | **10,178** | **11,016** | **55,761** | **83,494** |

[(1)] Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2013 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements.)

[(2)] See Note 14 of the Notes to the Consolidated Financial Statements.

[(3)] See Note 11 of the Notes to the Consolidated Financial Statements. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.

[(4)] Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

The contractual commitments table above excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 8 of the Notes to the Consolidated Financial Statements.

## NA TURAL GAS MATTERS

Since the San Bruno accident, PG&E Corporation and the Utility have incurred total cumulative charges of approximately $2.5 billion related to natural gas matters that are not recoverable through rates, as shown in the following table:

| (in millions) | 2013 | 2012 | 2011 | 2010 | Total |
|---|---|---|---|---|---|
| Pipeline-related expenses (1) | $ 387 | $ 477 | $ 483 | $ 63 | $ 1,410 |
| Disallowed capital (2) | 196 | 353 | - | - | 549 |
| Accrued fines (3) | 22 | 17 | 200 | - | 239 |
| Third-party liability claims (4) | 110 | 80 | 155 | 220 | 565 |
| Insurance recoveries (4) | (70) | (185) | (99) | - | (354) |
| Contribution (5) | - | 70 | - | - | 70 |
| **Total natural gas matters** | **$ 645** | **$ 812** | **$ 739** | **$ 283** | **$ 2,479** |

(1) Cumulative expenses through December 31, 2013 include PSEP-related expenses of $736 million and other gas safety-related work of $348 million.

(2) See "Disallowed Capital Costs" below.

(3) See "Pending CPUC Investigations" and "Other Enforcement Matters" below.

(4) The Utility has settled substantially all of the third-party liability claims related to the San Bruno accident. See "Operating and Maintenance" above and "Note 14 of the Consolidated Financial Statements" below.

(5) On March 12, 2012, the Utility and the City of San Bruno entered into an agreement under which the Utility contributed $70 million to support the city and the community's recovery efforts.

### Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident.

The SED has issued investigative reports and briefs in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations. In July 2013, the SED recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows: (1) $300 million as a fine to the State General Fund, (2) $435 million for a portion of costs related to the Utility's PSEP that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future costs. (See "Disallowed Capital Costs" below.) If the SED's penalty recommendation is adopted, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about $4.5 billion. Other parties, including the City of San Bruno, TURN, the CPUC's ORA, and the City and County of San Francisco, have recommended total penalties of at least $2.25 billion, including fines payable to the State General Fund of differing amounts.

The ALJs who oversee the investigations are expected to issue one or more presiding officers' decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued. Based on the CPUC's rules, the presiding officer's decisions would become the final decisions of the CPUC 30 days after issuance unless the Utility or another party filed an appeal with the CPUC, or a CPUC commissioner requested that the CPUC review the decision, within such time. If an appeal or review request is filed, other parties would have 15 days to provide comments but the CPUC could act before considering any comments.

At December 31, 2013, the Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including how the total number and duration of violations will be determined; how the various penalty recommendations made by the SED and other parties will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and how the CPUC will respond to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow PSEP costs that were previously authorized for recovery or other future costs. Disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance. See "Disallowed Capital Costs" below. Future disallowed expense and capital costs would be charged to net income in the period incurred.

**Other CPUC Enforcement Matters**

PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses that may be incurred in connection with the following matters.

*Gas Safety Citation Program.* The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of their natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility's operations or otherwise. The SED can exercise its discretion in determining whether to impose fines and the amount of such fines, or whether to take other enforcement action, based on the totality of the circumstances. The SED can consider such factors as the severity of the safety risk associated with each violation; the number and duration of the violations; whether the violation was self-reported, and whether corrective actions were taken. In January 2012, the SED imposed fines of $16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from $50,000 to $8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

*Natural Gas Transmission Pipeline Rights-of-Way.* In 2012, the Utility notified the CPUC and the SED that it is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments (such as building structures and vegetation overgrowth) from pipeline rights-of-way over a multi-year period. The SED could impose fines on the Utility or take other enforcement action in connection with this matter.

*Orders to Show Cause.* In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately $14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. The Utility recorded this amount as an expense for 2013. On January 23, 2014, the Utility filed an application for the rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable. Briefing on this OSC was completed on January 31, 2014.

**Disallowed Capital Costs**

In 2011, the CPUC ordered all natural gas operators in California to submit proposed plans to modernize and upgrade their natural gas transmission systems as well as associated cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP application that was filed in August 2011, but disallowed the Utility's request for rate recovery of a significant portion of costs the Utility forecasted it would incur through 2014. In October 2013, the Utility updated its PSEP application to present the results of its completed search and review of records relating to validation of operating pressure for all of the approximately 6,750 miles of the Utility's natural gas transmission pipelines. The Utility requested that the CPUC approve changes to the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects, and that the CPUC adjust authorized revenue requirements to reflect these changes. The Utility has requested that the CPUC issue a final decision by August 2014.

As of December 31, 2013, the Utility has recorded cumulative charges of $549 million for PSEP capital costs that are expected to exceed the amount to be recovered. The Utility has requested that the CPUC authorize capital costs of $766 million under the PSEP, reflecting the proposed changes in the PSEP update application. Of this amount, approximately $280 million is recorded in Property, Plant, and Equipment on the Consolidated Balance Sheets at December 31, 2013. The Utility could record additional charges to the extent PSEP capital costs are higher than currently expected, or if additional capital costs are disallowed by the CPUC. The Utility's ability to recover PSEP capital costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

**Criminal Investigation**

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. A criminal charge or finding would further harm the Utility's reputation. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

**Third-party Liability Claims**

See Note 14 of the Notes to the Consolidated Financial Statements.

**Class Action Complaint**

On August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages.

PG&E Corporation and the Utility contest the plaintiffs' allegations. On May 23, 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter if the lower court's ruling is reversed.

**Other Pending Lawsuits and Claims**

At December 31, 2013, there were also four purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits have filed a consolidated complaint with the San Mateo County Superior Court. The court has lifted the stay on these proceedings for the limited purpose of allowing the parties to exchange information and discuss possible resolution. A case management conference is scheduled for April 18, 2014. The remaining purported shareholder derivative lawsuit, filed in the U.S. District Court for the Northern District of California, remains stayed.

In February 2011, the Board of Directors of PG&E Corporation authorized PG&E Corporation to reject a demand made by another shareholder that the Board of Directors (1) institute an independent investigation of the San Bruno accident and related alleged safety issues; (2) seek recovery of all costs associated with such issues through legal proceedings against those determined to be responsible, including Board of Directors members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board of Directors also reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board of Directors deems such investigation or litigation appropriate.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

**RE GULATORY MATTERS**

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

**2014 General Rate Case**

On November 15, 2012, the Utility filed its 2014 GRC application with the CPUC. In the Utility's GRC, the CPUC will determine the revenue requirements that the Utility is authorized to collect through rates from 2014 through 2016 to recover anticipated costs associated with electric generation operations and electric and natural gas distribution operations. The Utility has requested that the CPUC authorize a total revenue requirement of $7.8 billion for 2014, representing an increase of approximately $1.16 billion over the comparable authorized revenues for 2013. The Utility also has requested that the CPUC authorize attrition increases in 2015 and 2016 of $436 million and $486 million, respectively. The requested increase is intended to allow the Utility to recover the costs it forecasts it will incur to continue making improvements to the safety and reliability of its operations.

The CPUC's ORA recommended that the Utility's 2014 revenue requirements be reduced by $125 million from amounts authorized in 2013, approximately $1.29 billion lower than the Utility's current forecast. The ORA also has recommended attrition increases of $169 million for 2015 and $160 million for 2016. The ORA's recommendations reflected reductions across all operations represented in the GRC. Twelve other parties, including TURN, also submitted recommendations in the 2014 GRC.

A proposed decision is anticipated in the first quarter of 2014. Although it is uncertain when the CPUC will issue a final decision, any approved revenue requirement changes will be effective as of January 1, 2014.

**2015 Gas Transmission and Storage Rate Case**

On December 19, 2013, the Utility filed its 2015 GT&S rate case application (covering 2015 through 2017) requesting the CPUC approve a total annual revenue requirement of $1.29 billion for anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2015. This is an increase of $555 million over the Utility's authorized revenue requirements of $731 million for 2014, which includes revenue requirements approved by the CPUC for both GT&S and PSEP. The Utility's forecasts for the 2015 GT&S rate case period are consistent with state law, which requires gas corporations to develop a plan to identify and minimize hazards and systemic risk for public and employee safety. The forecasts include the continuation of work begun in the Utility's PSEP, such as testing pipelines to verify safe operating pressures, replacing older pipelines, installing more valves, and inspecting the interior of more pipelines.

The Utility requested that the CPUC authorize the Utility's forecast of its 2015 weighted average rate base for its gas transmission and storage business of $3.56 billion, which includes the capital spend above authorized levels for the prior rate case period. The Utility also requested additional revenue requirement increases of $61 million in 2016 and $168 million in 2017 for increasing capital expenditures and the associated growth in rate base, as well as increasing costs of labor, materials, and other expenses. The Utility also has proposed eliminating the current mechanism that subjects a portion of the Utility's transportation-only revenue requirement to market risk, replacing it with two-way balancing accounts to allow the Utility to record differences between billed revenues and the Utility's authorized revenue requirements. Any over-collections would be returned to customers and any under-collections would be paid by customers, with no additional risk or benefit for shareholders.

The Utility has not requested rate recovery for certain costs it forecasts it will incur during 2015 through 2017. These forecast costs include costs related to the Utility's multi-year effort to identify and remove encroachments from gas transmission pipeline rights-of-way, approximately $75 million over the three year period to pressure test pipelines placed into service after 1961, and approximately $75 million of remedial costs associated with the Utility's pipeline corrosion control program over the three year period.

The Utility has requested that the CPUC issue a final decision by the end of 2014 so that any authorized revenue requirement adjustments can become effective on January 1, 2015. If the CPUC has not yet issued a final decision, then, in accordance with the CPUC's decision in the Utility's last GT&S rate case, there will be an automatic 2% increase in rates on January 1, 2015 that will remain in effect until the CPUC issues a final decision in the 2015 GT&S rate case. Given the significant revenue requirement increase the Utility has requested, the Utility plans to ask the CPUC for an order to make any authorized revenue requirement changes effective on January 1, 2015, in the event that the CPUC issues its final decision after that date.

The Utility's continued use of regulatory accounting under GAAP (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) for gas transmission and storage service depends on its ability to recover its cost of service. If the Utility were unable to continue using regulatory accounting under GAAP, there would be –differences in the timing of expense (or gain) recognition that could materially affect the Utility's future financial results.

**Electric Transmission Owner Rate Cases**

On January 17, 2014, the FERC approved the settlement of the Utility's TO rate case that was filed in September 2012. Under the settlement the Utility's annual retail revenue requirement was increased from $934 million to $1,017 million effective as of May 1, 2013. The Utility has collected revenues between May 1 and September 30, 2013 at the higher as-filed rates requested in the Utility's application. The Utility will refund to customers the difference between revenues collected at the higher as-filed rates and the rates set in the FERC-approved settlement agreement.

On September 24, 2013, the FERC accepted the Utility's TO rate case that the Utility filed on July 24, 2013, making the proposed rates effective October 1, 2013, subject to refund, pending a final decision by the FERC. The Utility requested a retail revenue requirement of $1,072 million and an ROE of 10.9%. The proposed rates represent a $55 million increase to the annual revenue requirement set in the FERC-approved settlement agreement described in the preceding paragraph. Hearings are currently being held in abeyance while settlement discussions are held.

**Oakley Generation Facility**

In December 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California. The CPUC authorized the Utility to recover the purchase price through rates. The CPUC's denial of various applications for rehearing that had been filed with respect to its December 2012 decision was appealed to the California Court of Appeal. On February 5, 2014, the California Court of Appeal issued a ruling that annulled the CPUC's decision after the court determined that the evidence presented did not support a finding of need for the Oakley facility. The Utility is reviewing the court's decision.

**Diablo Canyon Nuclear Power Plant**

In 2009, the Utility filed an application with the NRC to renew the operating licenses for the two operating units at Diablo Canyon. (The current licenses expire in 2024 and 2025.) In May 2011, after an earthquake and resulting tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan, the NRC granted the Utility's request to delay processing the Utility's application while certain advanced seismic studies were completed by the Utility. The Utility is currently assessing the data from recently completed advanced seismic studies along with other available seismic data. The Utility will not make any decisions about whether to request that the NRC resume processing the license renewal application until this assessment is completed and provided to the NRC. The Utility anticipates that it will complete its assessment by June 2014. In order for the NRC to issue renewed operating licenses, the California Coastal Commission must determine that license renewal is consistent with federal and state coastal laws. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel. The NRC has stated that it will not take action in licensing or re-licensing proceedings until it issues a new "waste confidence decision." (See "Risk Factors" below.)

The CPUC is considering the Utility's December 2012 application to recover estimated costs to decommission the Utility's nuclear facilities at Diablo Canyon and the retired nuclear facility Humboldt Bay Power Plant Unit 3. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover those costs through rates. The CPUC bifurcated the proceeding to allow for the decommissioning cost estimate associated with Humboldt Bay to be addressed first and all other matters (including the Diablo Canyon decommissioning cost estimate and all rate-related issues) to be addressed in a second phase. On January 28, 2014, the assigned ALJ issued a proposed decision in the first phase that would authorize $679 million to complete the decommissioning at Humboldt Bay, approximately $48 million lower than the amount requested by the Utility. The Utility anticipates that the CPUC will issue a final decision in the first quarter of 2014. In the second phase, TURN has recommended that the CPUC adopt a decommissioning cost estimate for Diablo Canyon that is approximately $1.1 billion lower than the Utility's estimate of approximately $2.8 billion. The Utility anticipates the CPUC will issue a proposed decision in the second phase during the second quarter of 2014. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennial Proceeding in Note 2 of the Notes to the Consolidated Financial Statements.)

**ENV IRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See "Risk Factors" below.)

**Remediation**

The Utility is required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. (See Note 14 of the Notes to the Consolidated Financial Statements.)

***Hinkley Site***

The Utility's remediation and abatement efforts at the Hinkley natural gas compressor site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. The Regional Board has certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue the final project permits and a final clean-up order in phases through 2014 and into 2015. As the permits and order are issued, the Utility will obtain additional clarity on the total costs associated with the final remedy and related activities. The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, monitor and control movement of the plume, and provided replacement water to affected residents. (See Note 14 of the Notes to the Consolidated Financial Statements for additional information.) At December 31, 2013, $190 million was accrued in the Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, the extent of the chromium plume boundary, and adoption of a final drinking water standard by the State of California. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

***Topock Site***

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. The Utility expects to submit its final remedial design plan in 2014 for approval to begin construction of an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River. At December 31, 2013, $264 million was accrued in the Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Topock site. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

**Climate Change**

A report issued in 2012 by the U.S. EPA entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. (See "Risk Factors" below.) Although no comprehensive federal legislation has been enacted to address the reduction of GHG emissions, the California legislature has taken action to address climate change.

California Assembly Bill 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB has approved various regulations to implement AB 32, including a state-wide, comprehensive "cap and trade" program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by the major sources of GHG emissions. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next three-year compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges in the market for trading GHG allowances. The CARB is allocating a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their electricity-related allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their electricity-related auction revenues among certain classes of their customers. Although the CPUC has previously authorized the utilities to recover their electricity-related GHG compliance costs through rates, the recovery of these costs has been temporarily deferred until May 2014. In addition, the CARB may allocate a number of allowances for free to natural gas suppliers, including the Utility, for the benefit of the Utility's natural gas customers. The Utility has filed requests at the CPUC for authority to recover the natural gas supplier-related compliance costs from natural gas customers on an annual basis effective January 1, 2015.

The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

**Clean Water Act**

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The California Water Board has appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at nuclear power plants, including Diablo Canyon. The committee's consultant is expected to submit a final report to the California Water Board in 2014. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

**OFF-BALANCE SHEET ARRANGEMENTS**

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 2 (PG&E Corporation's tax equity financing agreements) and Note 14 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements).

**RISK MANAGEMENT ACTIVITIES**

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

**Commodity Price Risk**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk.

The Utility uses value-at-risk to measure its shareholders' exposure to price and volumetric risks resulting from variability in the price of, and demand for, natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. The Utility's value-at-risk calculated under the methodology described above was approximately $14 million and $13 million at December 31, 2013 and 2012, respectively. During the 12 months ended December 31, 2013, the Utility's approximate high, low, and average values-at-risk were $14 million, $9 million and $12 million, respectively. During 2012, the value-at-risk amounts were $13 million, $10 million and $12 million, respectively. (See Note 9 of the Notes to the Consolidated Financial Statements for further discussion of price risk management activities.)

**Interest Rate Risk**

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2013 and December 31, 2012, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be $11 million and $7 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

**Energy Procurement Credit Risk**

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility ties many energy contracts to master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's credit risk exposure to its counterparties as of December 31, 2013 and December 31, 2012:

| (in millions) | Gross Credit Exposure Before Credit Collateral [1] | Credit Collateral | Net Credit Exposure [2] | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| December 31, 2013 | $ 87 | $ (9) | $ 78 | 2 | 34 |
| December 31, 2012 | 94 | $ (9) | $ 85 | 2 | 62 |

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.

(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

## CRI TICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

**Regulatory Accounting**

The Utility's rates are primarily set by the CPUC and the FERC and are designed to recover the cost of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods that the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, the Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other reduction of net allowable costs be given to customers over future periods.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods 2011 through 2013.

If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. At December 31, 2013, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $6.5 billion and regulatory liabilities (including current balancing accounts payable) of $6.8 billion.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures under construction (or recently completed expenditures) will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on the lower end of the range of possible losses to the extent there is a high degree of uncertainty in the Utility's forecast of capital project costs. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors. As discussed above in "Natural Gas Matters – Disallowed Capital Costs" and Note 14 of the Notes to the Consolidated Financial Statements, the Utility recorded charges of $196 million and $353 million in 2013 and 2012, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. The additional charge in 2013 primarily reflects changes in the project portfolio involving higher costs to replace pipelines than originally forecast. Management will continue to periodically assess its PSEP capital costs and the related CPUC regulatory proceedings, and further charges could be required in future periods.

**Loss Contingencies**

***Environmental Remediation Liabilities***

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former MGP sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former MGP sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2013 and 2012, the Utility's accruals for undiscounted gross environmental liabilities were $900 million and $910 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.7 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Legal and Regulatory Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are subject to claims or named as parties in lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the minimum amount, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amount of such losses, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs. (See "Natural Gas Matters" and "Legal and Regulatory Contingencies" in Note 14 of the Notes to the Consolidated Financial Statements.)

**Asset Retirement Obligations**

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. A legal obligation can arise from an existing or enacted law, statute, or ordinance; a written or oral contract; or under the legal doctrine of promissory estoppel.

At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process.

Most of PG&E Corporation's and the Utility's AROs relate to the Utility's obligation to decommission its nuclear generation facilities, certain fossil fuel-fired generation facilities, and gas transmission assets. The Utility estimates its obligation for the future decommissioning of its nuclear generation facilities and certain fossil fuel-fired generation facilities. In December 2012, the Utility submitted an updated estimate of the cost to decommission its nuclear facilities to the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by $1.4 billion in 2012 due to higher spent nuclear fuel disposal costs and an increase in the scope of work. To estimate the liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation. (See Note 2 of the Notes to the Consolidated Financial Statements.)

Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. Additionally, if the inflation adjustment increased 25 basis points, the amount of the ARO would increase by approximately 4.21%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 5.24%. At December 31, 2013, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $3.5 billion.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees.

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant a ctuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

PG&E Corporation and the Utility recognize the funded status of their respective plans on their respective Consolidated Balance Sheets with an offsetting entry to accumulated other comprehensive income (loss); or, to the extent that the cost of the plans are recoverable in utility rates, to regulatory assets and liabilities, resulting in no impact to their respective Consolidated Statements of Income.

Pension and other benefit expense is based on the differences between actuarial assumptions and actual plan results and is deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability for a portion of the credit balance in accumulated other comprehensive income. (See Note 3 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation and the Utility review recent cost trends and projected future trends in establishing health care cost trend rates. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2013 is 8%, gradually decreasing to the ultimate trend rate of 5% in 2020 and beyond.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 6.5% compares to a ten-year actual return of 8.7%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 494 Aa-grade non-callable bonds at December 31, 2013. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2013 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2013 |
|---|---|---|---|
| Discount rate | (0.50) % | $ 122 | $ 1,041 |
| Rate of return on plan assets | (0.50) % | 60 | - |
| Rate of increase in compensation | 0.50% | 60 | 246 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2013 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2013 |
|---|---|---|---|
| Health care cost trend rate | 0.50% | $ 7 | $ 43 |
| Discount rate | (0.50) % | 7 | 104 |
| Rate of return on plan assets | (0.50) % | 9 | - |

**CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS**

This 2013 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations; forecasts of costs the Utility will incur to make safety and reliability improvements, including natural gas transmission costs that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- when and how the pending CPUC investigations and enforcement matters related to the Utility's natural gas system operating practices and the San Bruno accident are concluded, including the ultimate amount of fines the Utility will be required to pay to the State General Fund, the amount of natural gas transmission costs the Utility will be prohibited from recovering, and the cost of any remedial actions the Utility may be ordered to perform;

- the outcome of the pending federal criminal investigation related to the San Bruno accident, including the ultimate amount of civil or criminal fines or penalties, if any, the Utility may be required to pay, and the impact of remedial measures the Utility is required to take such as the appointment of an independent monitor;

- whether PG&E Corporation and the Utility are able to repair the reputational harm that they have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident and the decisions to be issued in the pending investigations, including any charge or finding of criminal liability;

- the outcomes of ratemaking proceedings, such as the 2014 GRC, the 2015 GT&S rate case, and the TO rate cases;

- the amount and timing of additional common stock issuances by PG&E Corporation, the proceeds of which are contributed as equity to maintain the Utility's authorized capital structure as the Utility incurs charges and costs that it cannot recover through rates, including costs and fines associated with natural gas matters and the pending investigations;

- the outcome of future regulatory investigations, citations, or other proceedings, that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of its electric and gas facilities;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover environmental compliance and remediation costs in rates or from other sources; and the ultimate amount of environmental remediation costs the Utility incurs but does not recover, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; and whether the Utility decides to request that the NRC resume processing the Utility's renewal application for the two Diablo Canyon operating licenses, and if so, whether the NRC grants the renewal;

- the impact of weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;

- the impact of environmental laws and regulations aimed at the reduction of carbon dioxide and GHGs, and whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline in the Utility's service area, general and regional economic and financial market conditions, the extent of municipalization of the Utility's electric or gas distribution facilities, changing levels of "direct access" customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators," and the development of alternative energy technologies including self-generation, storage and distributed generation technologies;

- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its energy commodity costs through rates;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect confidential customer, vendor, and financial data contained in such systems and networks; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcome of the pending investigations relating to the Utility's natural gas operations affects the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, or regulations; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see "Risk Factors" below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

**RISK FACTORS**

***PG&E Corporation's and the Utility's reputations have been significantly affected by the negative publicity about the San Bruno accident, the related investigations and civil litigation, the Utility's noncompliance with certain natural gas regulations, and the fines imposed on the Utility for noncompliance with these regulations and for violation of certain CPUC rules. Their reputations may be further adversely affected by publicity regarding developments in the pending CPUC and criminal investigations, and by future investigations or other regulatory or governmental proceedings or action that may be commenced. In addition, the Utility's electricity and natural gas operations generally are subject to continuous public scrutiny and criticism that could lead to further reputational harm. Additional reputational harm or the inability of PG&E Corporation and the Utility to restore their reputations may further affect their financial conditions, results of operations and cash flows.***

The reputations of PG&E Corporation and the Utility have seriously suffered as a result of the extensive media coverage of the San Bruno accident, the investigative findings from the NTSB and the CPUC's independent review panel that placed the blame for the accident primarily on the Utility, the ensuing civil litigation, the criminal investigation, and the CPUC investigations that were commenced to determine whether the Utility violated any laws, rules, regulations or orders relating to safety recordkeeping, pipeline installation, integrity management, or other operational practices. (See "Natural Gas Matters" above.) PG&E Corporation and the Utility anticipate that there will be additional media coverage of future developments in the pending investigations, especially after the final outcomes are determined.

In addition, there could be additional negative publicity as the SED takes action with respect to numerous reports the Utility has submitted to notify the SED about the Utility's noncompliance with certain natural gas regulations. In January 2012, the SED imposed fines of $16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from $50,000 to $8.1 million for self-reported violations. The SED may impose additional fines based on other self-reported violations. The media also has published reports about two orders to show cause that were issued by the CPUC in August 2013 regarding a filing the Utility submitted in July 2013 to correct certain factual errors made in documents submitted in October 2011 that provided support for an order to restore operating pressure on certain pipelines. In December 2013, the Utility was fined $14.4 million for violating a CPUC rule prohibiting misleading disclosures to the CPUC.

The Utility's reputation can also be affected by media coverage of highly debated public policy issues such as those relating to the Utility's nuclear generation operations and nuclear decommissioning activities; environmental remediation or permitting activities; the accuracy, privacy, and safety of the Utility's information, operating, and billing systems; and the future development of the state-mandated California High Speed Rail project through the Utility's service territory. Media coverage of outages, vandalism, physical attacks on the Utility's facilities (such as the attack on the Metcalf electric substation), gas leaks, accidents causing injury or death, or other operational events, as well as concerns about the risks of terrorist acts, climate change, earthquakes, or a nuclear accident, can also negatively affect the Utility's reputation. These public policy debates and operational concerns have often led to additional adverse media coverage and could later result in investigations or other action by regulators, legislators and law enforcement officials or in lawsuits.

The outcome of pending ratemaking proceedings, such as the GRC and the GT&S rate case, also could affect PG&E Corporation's and the Utility's reputations, with unfavorable regulatory outcomes having a negative reputational effect. Alternatively, PG&E Corporation's or the Utility's unfavorable reputation could have a negative influence on the regulatory decision-making process.

Investors may question management's ability to repair the reputational harm that PG&E Corporation and the Utility have suffered, resulting in an adverse impact on the market price of PG&E Corporation common stock. The issuance of common stock by PG&E Corporation to fund the Utility's unrecovered costs has materially diluted PG&E Corporation's EPS. Additional share issuances following a declining stock price would cause further dilution. The extent to which PG&E Corporation's and the Utility's reputations can be restored will depend, in part, on the success of the Utility's efforts to improve the safety and reliability of the natural gas system as planned in the Utility's PSEP, whether they can implement the remaining recommendations made by the CPUC's independent review panel and the NTSB, and whether they are able to adequately show regulators, legislators, law enforcement officials, city officials, the media and the public that they have done so. If PG&E Corporation and the Utility are unable to repair their reputations, their financial conditions, results of operations and cash flows may continue to be negatively affected.

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected by the ultimate outcome of the CPUC investigations; the ultimate amount of gas transmission costs that the Utility does not recover through rates; and the ultimate outcome of the criminal investigation, including the amount of penalties imposed and the cost to implement any required action.***

As discussed above in the section entitled "Natural Gas Matters − Pending CPUC Investigations and Enforcement Matters," the SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.95 billion of non-recoverable costs. If the SED's penalty recommendation is adopted by the CPUC, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about $4.5 billion and the Utility would incur material charges in addition to the charges already incurred for the probable fines of $200 million and unrecoverable natural gas transmission costs. Such charges would materially affect PG&E Corporation's and the Utility's financial condition and results of operations and could negatively affect the availability, amount, and timing of future debt and equity issuances by PG&E Corporation and the Utility. Future developments in the criminal investigation arising from the San Bruno accident also could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. (See the sections entitled "Criminal Investigation" under the heading "Natural Gas Matters.")

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been materially affected by costs incurred by the Utility to perform work under the PSEP, to undertake other pipeline-related work, and to improve the safety and reliability of its natural gas and electricity operations. The Utility forecasts that it will incur a material amount of unrecoverable natural gas transmission costs in 2014. The Utility's ability to recover natural gas transmission costs in 2015 through 2017 primarily will be determined by the outcome of the Utility's 2015 GT&S rate case.***

In December 2012, the CPUC approved most of the Utility's proposed scope and timing of projects to be completed under the Utility's PSEP through 2014, but the CPUC disallowed the Utility's request for rate recovery of a significant portion of forecasted capital costs and expenses. In October 2013, the Utility filed an update application, as ordered by the CPUC, to reflect changes in the scope and priority of projects resulting from the Utility's completed search and review of records related to pipeline pressure validation and other information, including updated cost forecasts. At

December 31, 2013, the Utility had recorded cumulative charges of $549 million for PSEP capital costs that the Utility expects will exceed the adopted cost amounts. (See "Natural Gas Matters" above.) The Utility could record additional charges for disallowed costs if the CPUC does not approve the Utility's request to adjust revenue requirements or if cost forecasts increase. The Utility also forecasts it will incur costs during 2014 that it will not recover through rates, including costs to identify and remove encroachments from gas transmission pipeline rights-of-way, to pressure test pipelines placed into service after January 1, 1956, consistent with the CPUC's disallowance of such costs in the PSEP decision, and remedial costs associated with the Utility's pipeline corrosion control program.

The Utility's ability to recover its natural gas transmission and storage costs in 2015, 2016, and 2017, will be determined by whether the CPUC approves the Utility's GT&S rate case application. (See "Regulatory Matters" above.) PG&E Corporation's and the Utility's financial condition and results of operations could be materially affected if the CPUC does not approve the Utility's request or if actual costs exceed the capital and expense amounts that the CPUC may authorize. The Utility has not requested rate recovery for certain costs it forecasts it will incur during 2015 through 2017, including costs to identify and remove encroachments from gas transmission pipeline rights-of-way, to pressure test certain pipelines, and to take remedial measures to address pipeline corrosion. Actual costs to perform this work could materially exceed forecasts and negatively affect PG&E Corporation's and the Utility's results of operations. The Utility's ability to recover natural gas transmission costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.***

The Utility relies on access to capital and credit markets as significant sources of liquidity to fund capital expenditures, pay principal and interest on its debt, provide collateral to support its natural gas and electricity procurement hedging contracts, and fund other operations requirements that are not satisfied by operating cash flows. See the discussion of the Utility's future financing needs above in "Liquidity and Financial Resources." The Utility's financing needs would increase if the Utility were required to incur unrecoverable costs and pay fines as a result of the outcome of the pending investigations discussed in "Natural Gas Matters" above. Such financing may become more difficult to obtain, especially if the ultimate outcome of the investigations affected the Utility's credit ratings. As the Utility has incurred costs it has been unable to recover through rates, it has relied on equity contributions from PG&E Corporation to maintain the 52% equity component of its CPUC-authorized capital structure. The Utility's equity needs could increase materially depending on the ultimate outcome of the pending investigations and the amount of natural gas and transmission costs it is unable to recover through rates.

PG&E Corporation relies on independent access to the capital and credit markets to fund its operations, make capital expenditures, and contribute equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure, if funds received from the Utility (in the form of dividends or share repurchases) are insufficient to meet such needs. Since the San Bruno accident, PG&E Corporation has issued a material amount of equity to fund its equity contributions to the Utility. PG&E Corporation forecasts that it will need to issue additional material amounts of equity in 2014 as the Utility continues to incur costs that it cannot recover through rates. If the Utility is required to pay penalties in an amount that exceeds the amount already accrued, the Utility may need further equity contributions that PG&E Corporation may need to fund through additional dilutive share issuances. PG&E Corporation also may be required to access the capital markets to fund equity contributions to the Utility following the Utility's issuance of long-term debt to maintain the Utility's capital structure. PG&E Corporation primarily has relied on the public sale of its common stock to raise the funds it contributes to meet the Utility's equity needs. The market price of PG&E Corporation common stock could decline materially depending on the outcome of the investigations and the amount and timing of future share issuances. Declines in the stock price could increase the dilutive effect of future stock issuances and make it more difficult or expensive for PG&E Corporation to complete future equity offerings.

PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend on many factors, including the ultimate outcome of the pending investigations, the outcome of pending ratemaking proceedings, changes in their credit ratings, changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, volatility in electricity or natural gas prices, and general economic and financial market conditions. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing capital to the Utility, to enable the Utility to fulfill its obligation to serve. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

***PG&E Corporation's and the Utility's financial condition depends upon the Utility's ability to recover its operating expenses and its electricity and natural gas procurement costs and to earn a reasonable rate of return on capital investments, in a timely manner from the Utility's customers through regulated rates.***

The Utility's ability to recover its costs and earn its authorized rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers' rates and differences between the forecast or authorized costs embedded in rates (which are set on a prospective basis) and the amount of actual costs incurred. (See "Regulatory Matters – 2014 General Rate Case" above.) The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. For example, the CPUC has prohibited the Utility from recovering a material portion of costs that the Utility has already incurred, and will continue to incur, as it performs work under the PSEP, in part, because the CPUC found that such costs were incurred as a result of imprudent management. The CPUC may order the Utility to propose cost-sharing methods for certain costs or the Utility may decide for other reasons not to seek recovery of certain costs. In either case, the Utility would incur costs that are not recovered through rates. (See "Natural Gas Matters" above.)

Further, to serve its customers in a safe and reliable manner, the Utility may be required to incur expenses before the CPUC approves the recovery of such costs. The Utility is generally unable to recover costs incurred before CPUC authorization is obtained, unless the CPUC authorizes the Utility to track costs for potential future recovery. For example, the Utility requested that the CPUC allow the Utility to track costs incurred in 2012 under the PSEP before the CPUC approved the plan. The CPUC did not address the Utility's request and as a result the Utility was unable to recover costs incurred before the effective date of the decision, December 20, 2012. The Utility's failure to recover these and other pipeline-related costs has materially affected PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

Changes in laws and regulations or changes in the political and regulatory environment also may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. In addition, the Utility may be required to incur substantial costs to comply with new state laws or to implement new state policies before the Utility is assured of cost recovery. For example, the state-mandated development of the

California High Speed Rail Project through the Utility's service territory will require the relocation of some of the Utility's electric and gas facilities, new electric facilities, and significant expansion and upgrade to the Utility's electric system. Although the CPUC has begun a proceeding to address cost allocation and cost recovery issues, the Utility may incur costs before the issues are settled, for example, to obtain environmental permits. Further, fluctuating commodity prices also could affect the Utility's ability to timely recover its costs and earn its authorized rate of return. Although current law and regulatory mechanisms permit the Utility to pass through its costs to procure electricity and natural gas to customers in rates, a significant and sustained rise in commodity prices, caused by costs associated with new renewable energy resources and California's new cap-and-trade program and other factors, could create overall rate pressures that make it more difficult for the Utility to recover its costs. This pressure could increase as the Utility continues to collect authorized rates to support public purpose programs, such as energy efficiency programs, and low-income rate subsidies, and to fund customer incentive programs.

The Utility's ability to recover its costs also may be affected by the economy and the economy's corresponding impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base. A portion of the Utility's revenues depends on the level of customer demand for the Utility's natural gas transportation services which can fluctuate based on economic conditions, the price of natural gas, and other factors. In the GT&S rate case application, the Utility has proposed that this revenue mechanism be eliminated beginning on January 1, 2015 but it is uncertain whether the request will be granted.

The Utility's failure to recover its operating expenses, including electricity and natural gas procurement costs in a timely manner through rates could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

***The Utility's ability to procure electricity to meet customer demand at reasonable prices and recover procurement-related costs timely may be affected by increasing renewable energy requirements, the continuing functioning of the wholesale electricity market in California, and the expanded cap-and-trade market.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch."

Following competitive requests for offers from third parties, the Utility enters into power purchase agreements, including contracts to purchase renewable energy, in compliance with a CPUC-approved long-term procurement plan. These agreements become binding obligations of the Utility after the CPUC approves the agreements and authorizes the Utility to recover contract costs through rates. There is a risk that the contractual prices the Utility is required to pay will become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to economic conditions or the loss of the Utility's customers to other generation providers. In particular, as the market for renewable energy develops in response to California's renewable energy requirements, there is a risk that the Utility's contractual commitments could result in procurement costs that are higher than the market price of renewable energy. This could create a further risk that, despite original CPUC approval of the contracts, the CPUC would disallow contract costs in the future if the CPUC determines that the costs are unreasonably above market. In addition, the CPUC could disallow procurement costs if the CPUC determined that the Utility incurred procurement costs that were not in compliance with its CPUC-approved procurement plan, or that the Utility did not prudently administer the power purchase agreements that were executed in compliance with the plan. The Utility also could incur liability under its contracts to procure electricity from conventional and renewable generation resources if such resources are physically curtailed by the CAISO during periods of over-generation when generation resources scheduled with the CAISO exceed customer load. The costs incurred by the Utility under these circumstances would be subject to reasonableness review by the CPUC and could be disallowed.

The Utility also purchases energy through the day-ahead and real-time wholesale electricity market operated by the CAISO. The amount of electricity the Utility purchases on the wholesale market fluctuates due to a variety of factors, including, the level of electricity generated by the Utility's own generation facilities, changes in customer demand, periodic expirations or terminations of power purchase contracts, the execution of new power purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, and the implementation of new energy efficiency and demand response programs. The market prices of electricity also fluctuate due to various factors, including the type of generation resources. Hydroelectric generation resources are generally the least expensive. As drought conditions in California and the Western U.S. persist, the market prices of electricity will generally reflect the higher cost of conventional and other resources. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended due to a cyber-attack or other reason, which could result in excessive market prices. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

In addition, electricity costs include the costs to comply with California's cap-and-trade regulations. Although some of these costs can be offset by revenues from the sale of emission allowances by the Utility on behalf of some classes of electricity customers, it is uncertain how the cap-and-trade market will develop in the future especially as the cap-and-trade compliance periods expand to cover other sources of GHG emissions and as other regional or federal cap-and-trade programs are adopted.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected if the Utility is unable to recover a material portion of the costs it incurs to deliver electricity to customers.

***The completion of capital investment projects is subject to substantial risks, and the timing of the Utility's capital expenditures and recovery of capital-related costs through rates, if at all, will directly affect net income.***

The Utility's ability to invest capital in its electric and natural gas businesses is subject to many risks, including risks related to obtaining regulatory approval, securing adequate and reasonably priced financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party contractors on which the Utility depends to develop or construct these projects also face many of these risks. Changes in tax laws or policies, such as those relating to "bonus" depreciation, may also affect when or whether a potential project is developed. In addition, reduced forecasted demand for electricity and natural gas as a result of an economic slow-down, or other reasons, may also increase the risk that projects are deferred, abandoned, or cancelled. Some of the Utility's future capital investments may also be affected by evolving federal and state policies regarding the development of a "smart" electric transmission grid.

In addition, differences in the amount or timing of actual capital expenditures compared to the amount and timing of forecast capital expenditures authorized to be recovered through rates, can directly affect net income. Changes in regulatory policies concerning ongoing recovery of costs for existing projects may increase risks associated with capital investment. Further, if capital expenditures are disallowed, the Utility would be required to write-off such expenses which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations. For example, at December 31, 2013, the Utility had recorded cumulative charges of $549 million for PSEP capital costs that the CPUC has

specifically disallowed and for increases in the amount of costs that the Utility forecasts will exceed the adopted cost amounts.

***PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth due to municipalization, an increase in the number of community choice aggregators, increasing levels of "direct access," and the development and integration of self-generation and distributed generation technologies, if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility's customers could bypass its distribution and transmission system by obtaining such services from other providers. This may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers. In addition, local government agencies could exercise their power of eminent domain to acquire the Utility's facilities and use the facilities to provide utility service to their local residents and businesses. The Utility may be unable to fully recover its investment in the distribution assets that it no longer owns. The Utility's natural gas transmission facilities could be bypassed by interstate pipeline companies that construct facilities in the Utility's markets, by customers who build pipeline connections that bypass the Utility's natural gas transmission and distribution system, or by customers who use and transport liquefied natural gas.

Alternatively, the Utility's customers could become direct access customers who purchase electricity from alternative energy suppliers or they could become customers of governmental bodies registered as community choice aggregators to purchase and sell electricity for their residents and businesses. Although the Utility is permitted to collect a non-bypassable charge for generation-related costs incurred on behalf of these customers, or distribution, metering, or other services it continues to provide, the fee may not be sufficient for the Utility to fully recover the costs to provide these services. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, could put upward rate pressure on remaining customers. Also, a confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments.

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, increasing self-generation and net energy metering, and the growth of distributed generation and storage, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

***The operation of the Utility's electricity and natural gas generation, transmission, and distribution facilities involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial condition, results of operations and cash flows, and the Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. The Utility's service territory covers approximately 70,000 square miles in northern and central California and is composed of diverse geographic regions with varying climates, weather conditions, vegetation amounts, and population density levels, all of which create numerous operating challenges. The Utility's facilities are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. These facilities are subject to physical attacks, including cyber-attacks that can cause local or widespread outages of electric or natural gas service, or otherwise disrupt operations, as well as cause property damage and personal injury. The Utility and other industry participants implement various security measures to monitor and protect their facilities but these security measures may not always be successful. The Utility's ability to earn its authorized rate of return depends on its ability to efficiently maintain, operate, and protect its facilities and provide electricity and natural gas services safely and reliably. The maintenance and operation of the Utility's facilities, and the facilities of third parties on which the Utility relies, involve numerous risks, including the risks discussed elsewhere in this section and those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;
- the failure of generation facilities to perform at expected or at contracted levels of output or efficiency;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's electric transmission assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event, and the failure to respond effectively to a catastrophic event;
- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wildland and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;
- operator or other human error;
- construction performed by third parties, such as ground excavation that damages the Utility's underground facilities;
- fuel supply interruptions or the lack of available fuel which reduces or eliminates the Utility's ability to provide electricity and/or natural gas service;
- the release of hazardous or toxic substances into the air or water;

- use of new or unproven technologies;
- attacks by third parties, including cyber-attacks; and
- acts of terrorism, vandalism, or war.

The occurrence of any of these events could affect demand for electricity or natural gas; cause unplanned outages or reduce generating output which may require the Utility to incur costs to purchase replacement power; cause damage to the Utility's assets or operations requiring the Utility to incur unplanned expenses to respond to emergencies and make repairs; damage the assets or operations of third parties on which the Utility relies; subject the Utility to claims by customers or third parties for damages to property, personal injury, or wrongful death, or subject the Utility to penalties. These costs may not be recoverable through rates or insurance. Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage or may not be available at all.

***The Utility's operational and information systems on which it relies to conduct its business and serve customers could fail to function properly due to technological problems, cyber-attacks, physical attacks on the Utility's assets, acts of terrorism, severe weather, solar events, electromagnetic events, natural disasters, the age and condition of information technology assets, human error, or other reasons, that could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense.***

The operation of the Utility's extensive electricity and natural gas systems rely on evolving information and operational technology systems and network infrastructures that are becoming more complex as new technologies and systems are implemented to modernize capabilities to safely and reliably deliver gas and electric services. The Utility's business is highly dependent on its ability to process and monitor, on a daily basis, a very large number of tasks and transactions, many of which are highly complex. The failure of the Utility's information and operational systems and networks due to a physical attack, cyber-attack or other cause could significantly disrupt operations; cause harm to the public or employees; result in outages or reduced generating output; damage to the Utility's assets or operations or those of third parties; and subject the Utility to claims by customers or third parties, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require constant maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. Any disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification or implementation of new systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively affect the effectiveness of the companies' control environment, and/or the companies' ability to timely file required regulatory reports.

The Utility's ability to measure customer energy usage and generate bills depends on the successful functioning of the advanced metering system. The Utility relies on third party contractors and vendors to service, support, and maintain certain proprietary functional components of the advanced metering system. If such a vendor or contractor ceased operations, if there was a contractual dispute or a failure to renew or negotiate the terms of a contract so that the Utility becomes unable to continue relying on such a third-party vendor or contractor, then the Utility could experience costs associated with disruption of billing and measurement operations and would incur costs as it seeks to find other replacement contractors or vendors or hire and train personnel to perform such services.

Despite implementation of security and mitigation measures, all of the Utility's technology systems are vulnerable to disability or failures due to cyber-attacks, physical attacks on the facilities and equipment needed to operate the technology systems, viruses, human errors, acts of war or terrorism, and other events. If the Utility's information technology systems or network infrastructure were to fail, the Utility might be unable to fulfill critical business functions and serve its customers, which could have a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.

In addition, in the ordinary course of its business, the Utility collects and retains sensitive information including personal identification information about customers and employees, customer energy usage, and other confidential information. The theft, damage, or improper disclosure of sensitive electronic data can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, and harm the Utility's reputation.

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility's workforce is aging and many employees will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may not be successful. The Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. The terms of these agreements affect the Utility's labor costs. It is possible that labor disruptions could occur. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future. It is also possible that PG&E Corporation and the Utility may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the San Bruno accident. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities that it may not be able to recover from its insurance or other sources, and the Utility may incur significant capital expenditures and compliance costs that it may be unable to fully recover, adversely affecting PG&E Corporation's and the Utility's s financial conditions, results of operations, and cash flows.***

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. There are also significant uncertainties related to the regulatory, technological, and financial aspects of decommissioning nuclear generation plants when their licenses expire. To reduce the Utility's financial exposure to these risks, the Utility maintains insurance and manages decommissioning trusts that hold nuclear decommissioning charges collected through customer rates. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of its nuclear power plants could exceed the amount of the Utility's insurance coverage and nuclear decommissioning trust assets. The Utility has insurance coverage for property damages and business interruption losses, as well as coverage for acts of terrorism at its nuclear power plants as a member of NEIL, a mutual insurer owned by utilities with nuclear facilities. NEIL provides coverage for both nuclear (meaning that nuclear material is released) and non-nuclear losses. Due to multiple large non-nuclear losses in the industry, in 2013 NEIL significantly reduced its coverage for non-nuclear losses. While the Utility is seeking alternative insurance options, efforts to obtain additional coverage may not be successful. Even if the Utility is able to obtain additional coverage, this future insurance coverage may not be available at rates and terms as favorable as the rates and terms of the Utility's current NEIL insurance coverage. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

In addition, as an operator of the two operating nuclear reactor units at Diablo Canyon, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 14 of the Notes to the Consolidated Financial Statements.) The Utility's ability to continue to operate its nuclear generation facilities also is subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable.

The NRC oversees the licensing, construction, and decommissioning of nuclear facilities and has broad authority to impose requirements relating to the maintenance and operation of nuclear facilities; the storage, handling and disposal of spent fuel; and the safety, radiological, environmental, and security aspects of nuclear facilities. The NRC has adopted regulations that are intended to protect nuclear facilities, nuclear facility employees, and the public from potential terrorist and other threats to the safety and security of nuclear operations, including threats posed by radiological sabotage or cyber-attack. The Utility incurs substantial costs to comply with these regulations. In addition, in March 2012, the NRC issued several orders to the owners of all U.S. operating nuclear reactors to implement the highest-priority recommendations issued by the NRC's task force to incorporate the lessons learned from the March 2011 earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan. The NRC may issue further orders to implement the recommendations, including facility-specific orders, which could require the Utility to incur additional costs.

In 2009, the Utility filed an application with the NRC to renew the operating licenses for the two operating units at Diablo Canyon. (See "Regulatory Matters – Diablo Canyon Nuclear Power Plant" above.) In May 2011, after the Fukushima-Dai-ichi event, the NRC granted the Utility's request to delay processing the Utility's application while certain advanced seismic studies were completed. The Utility is currently assessing the data from recently completed advanced seismic studies along with other available seismic data. The Utility will not make any decision about whether to request that the NRC to resume processing the license renewal application until this assessment is completed and provided to the NRC. The Utility anticipates that it will complete this assessment by June 2014. If the Utility does not request that the NRC resume processing the application, the current operating licenses would expire in 2024 and 2025. In any event, the NRC has stated that it will not issue final decisions in licensing or re-licensing proceedings, including the Utility's re-licensing application, until it has issued a new "waste confidence decision," as described below. In addition, the NRC would not issue renewed operating licenses for Diablo Canyon unless the California Coastal Commission determined that license renewal is consistent with federal and state coastal laws.

In the NRC's original "waste confidence decision," the NRC found that spent nuclear fuel can be safely managed until a permanent off-site repository is established. The NRC's waste confidence decision was successfully challenged on the basis that the NRC's environmental review was deficient. The NRC has instructed its staff to develop and issue a new waste confidence decision and temporary storage rule by October 2014. It is uncertain how the new waste confidence decision and temporary storage rule would affect the Utility's decision to resume the renewal application process at the NRC or, if the application process were resumed, how the new waste confidence decision and temporary storage rule would affect the disposition of the renewal application. It is also uncertain how the new waste confidence decision and temporary storage rule would affect the Utility's nuclear generation operations during the current terms of the NRC licenses for Diablo Canyon.

The CPUC has authority to determine the rates the Utility can collect to recover its nuclear fuel, operating, maintenance, compliance, and decommissioning costs. The Utility also could incur significant expense to comply with regulations or orders the NRC may issue in the future to impose new safety requirements, to obtain license renewal, and to comply with federal and state policies and regulations applicable to the use of cooling water intake systems at generation facilities, such as Diablo Canyon. (See "Environmental Matters" above.) The Utility expects that it would seek rate recovery of these additional costs. The outcome of these rate proceedings at the CPUC can be influenced by public and political opposition to nuclear power.

If the Utility were unable to recover costs related to its nuclear facilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders, including a new waste confidence decision, in a feasible and economic manner and voluntarily cease operations at Diablo Canyon. Alternatively, the NRC may order the Utility to cease its nuclear operations until it can comply with new regulations, orders, or decisions. Further, the Utility could decide not to resume the license renewal process or the Utility could fail to obtain renewed operating licenses for Diablo Canyon requiring nuclear operations to cease when the current licenses expire in 2024 and 2025.

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility can incur significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. These costs can be difficult to forecast because the extent of contamination may be unknown. For example, the Utility's costs to perform hydrostatic pressure tests on natural gas pipelines were higher than anticipated because the water used to perform the tests became contaminated as it traveled through the pipe and the Utility had to incur additional costs to remediate the contaminated wastewater. Further, even if the extent of contamination is known, remediation costs can be difficult to estimate due to many factors, including which remediation alternatives will be used, the applicable remediation levels, and the financial ability of other potentially responsible parties. Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites, some of which the Utility no longer owns, include former manufactured gas plant sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. Although the Utility has liabilities for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. (See Note 14 to the Notes to the Consolidated Financial Statements for more information.)

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows. (See "Environmental Matters" above.)

***The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.***

A report issued in 2012 by the EPA entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. In December 2009, the EPA issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. The impact of events or conditions caused by climate change could range widely, from highly localized to worldwide, and the extent to which the Utility's operations may be affected is uncertain. For example, if reduced snowpack decreases the Utility's hydroelectric generation, the Utility will need to acquire additional generation from other sources at a greater cost. In addition, if lower hydroelectric generation due to dry conditions or prolonged drought increases reliance on conventional generation resources, it may be more costly for the Utility to comply with California's renewable portfolio standard program and GHG emissions limits.

Under certain circumstances, the events or conditions caused by climate change could result in a full or partial disruption of the ability of the Utility – or one or more of the entities on which it relies – to generate, transmit, transport, or distribute electricity or natural gas. The Utility has been studying the potential effects of climate change on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

***The Utility is subject to fines and penalties for failure to comply with federal, state, or local statutes and regulations. Changes in the political and regulatory environment could cause federal and state statutes, regulations, rules, and orders to become more stringent and difficult to comply with, and required permits, authorizations, and licenses may be more difficult to obtain, increasing the Utility's expenses or making it more difficult for the Utility to execute its business strategy.***

The Utility must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. In addition to the NRC requirements described above, these include meeting new renewable energy delivery requirements, resource adequacy requirements, federal electric reliability standards, customer billing, customer service, affiliate transactions, vegetation management, operating and maintenance practices, and safety and inspection practices. The Utility is subject to penalties and sanctions for failure to comply with applicable statutes, regulations, rules, tariffs, and orders.

The CPUC can impose fines up to $50,000 per day, per violation. The CPUC has wide discretion to determine, based on the facts and circumstances, whether a single violation or multiple violations were committed and to determine the length of time a violation existed for purposes of calculating the amount of fines. The CPUC has delegated authority to the SED to levy citations and impose fines for violations of certain regulations related to the safety of natural gas facilities and utilities' natural gas operating practices. Like the CPUC, the SED has discretion to determine how to count the number of violations, but the delegated authority requires the SED to assess the maximum statutory fine per violation with discretion to adjust the amount of the fine based on the risk-level of the violation as determined by the SED. (For a discussion of pending investigations and potential enforcement proceedings, see MD&A "Natural Gas Matters" above.) A California law enacted in 2013 requires the CPUC to establish a safety enforcement program for gas facilities by July 1, 2014 and for electric facilities by January 1, 2015. The law requires the CPUC to delegate enforcement authority to the SED under these programs. The CPUC may make changes to its gas safety enforcement program to implement the new law. These programs may increase the risk that penalties will be imposed on the Utility.

In addition, the federal Pipeline and Hazardous Materials Safety Administration has independent authority to impose fines for violation of federal pipeline safety regulations in amounts that range from $100,000 to $200,000 for an individual violation and from $1 million to $2 million for a series of violations.

The Utility must comply with federal electric reliability standards that are set by the North American Electric Reliability Corporation and approved by the FERC. These standards relate to maintenance, training, operations, planning, vegetation management, facility ratings, and other subjects. These standards are designed to maintain the reliability of the nation's bulk power system and to protect the system against potential disruptions from cyber-attacks and physical security breaches. Regulatory authorities conduct frequent compliance audits of the Utility's operating practices. The FERC can impose fines (up to $1 million per day, per violation) for failure to comply with these mandatory electric reliability standards. As these and other standards and rules evolve, and as the wholesale electricity markets become more complex, the Utility's risk of noncompliance may increase.

In addition, statutes, regulations, rules, tariffs, and orders, or their interpretation and application, may become more stringent and difficult to comply with in the future. If this occurs, the Utility could be exposed to increased costs to comply with the more stringent requirements or new interpretations and to potential liability for customer refunds, penalties, or other amounts. If it is determined that the Utility did not comply with applicable statutes, regulations, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially affected.

The Utility also must comply with the terms of various governmental permits, authorizations, and licenses. These permits, authorizations, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, waste discharge permits and other approvals and licenses often have a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, or licenses, or if the Utility cannot recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially affected.

***Market performance or changes in other assumptions could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. Up to approximately 60% of the plan assets and trust assets have generally been invested in equity securities, which are subject to market fluctuation. A decline in the market value may increase the funding requirements for these plans and trusts.

The cost of providing pension and other postretirement benefits is also affected by other factors, including the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. Funding requirements also can be affected by the difference between the actual rate of return on plan assets and the assumed rate and by changes in the assumed rate of return. For example, changes in interest rates affect the liabilities under the plans: as interest rates decrease, the liabilities increase, potentially increasing the funding requirements.

The Utility has recorded an asset retirement obligation related to decommissioning its nuclear facilities based on various estimates and assumptions. Changes in these estimates and assumptions can materially affect the amount of the recorded asset retirement obligation. (See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the increase in the recorded asset retirement obligation to reflect increased estimated decommissioning costs.)

The CPUC has authorized the Utility to recover forecasted costs to fund pension and postretirement plan contributions and nuclear decommissioning through rates. If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans and nuclear decommissioning trusts and is unable to recover such contributions in rates, the contributions would negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Other Utility obligations, such as its workers' compensation obligations, are not separately earmarked for recovery through rates. Therefore, increases in the Utility's workers' compensation liabilities and other unfunded liabilities also can negatively affect net income.

***PG&E Corporation's and the Utility's financial statements reflect various estimates, assumptions, and values and are prepared in accordance with applicable accounting rules, standards, policies, guidance, and interpretations, including those related to regulatory assets and liabilities. Changes to these estimates, assumptions, values, and accounting rules, or changes in the application of these rules, could materially affect PG&E Corporation's and the Utility's financial condition or results of operations.***

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets, and liabilities, and the disclosure of contingencies. (See the discussion under Notes 1 and 2 of the Notes to the Consolidated Financial Statements and "Critical Accounting Policies" above.) If the information on which the estimates and assumptions are based proves to be incorrect or incomplete, if future events do not occur as anticipated, or if there are changes in applicable accounting guidance, policies, or interpretation, management's estimates and assumptions will change as appropriate. A change in management's estimates or assumptions, or the recognition of actual losses that differ from the amount of estimated losses, could have a material impact on PG&E Corporation's and the Utility's financial condition or results of operations.

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility's continued use of regulatory accounting (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) depends on its ability to recover its cost of service. (See Note 3 of the Notes to the Consolidated Financial Statements.) Since the San Bruno accident, the Utility has recorded cumulative charges of approximately $2.5 billion related to its natural gas operations that are not recoverable through rates. (See "Natural Gas Matters" above.) To the extent that rates, including rates in the 2015 GT&S rate case, are not set at a level that allows the Utility to recover the cost of providing service and a reasonable return on its investment in future periods, the Utility may be required to discontinue the application of regulatory accounting for portions of its operations. If that occurs, the related regulatory assets and liabilities would be charged against income in the period in which that determination was made and could have a material impact on PG&E Corporation's and the Utility's future financial condition and results of operations. In addition, if regulatory accounting did not apply, the Utility's future financial results could become more volatile under GAAP accounting as compared to historical financial results under regulatory accounting due to the differences in the timing of expense (or gain) recognition under GAAP accounting as compared to regulatory accounting.

***As a holding company, PG&E Corporation depends on cash distributions and reimbursements from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.***

PG&E Corporation is a holding company with no revenue generating operations of its own. PG&E Corporation's ability to pay interest on its outstanding debt, the principal at maturity, and to pay dividends on its common stock, as well as satisfy its other financial obligations, primarily depends on the earnings and cash flows of the Utility and the ability of the Utility to distribute cash to PG&E Corporation (in the form of dividends and share repurchases) and reimburse PG&E Corporation for the Utility's share of applicable expenses. Before it can distribute cash to PG&E Corporation, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors. The Utility's ability to pay common stock dividends is constrained by regulatory requirements, including that the Utility maintain its authorized capital structure with an average 52% equity component. PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. If the Utility is not able to make distributions to PG&E Corporation or to reimburse PG&E Corporation, PG&E Corporation's ability to meet its own obligations could be impaired and its ability to pay dividends could be restricted. (Also see the discussion of financing risks above.)

***PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.***

The CPUC imposed certain conditions when it approved the original formation of a holding company for the Utility, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC later issued decisions adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The Utility's financial condition will be affected by the amount of costs the Utility incurs that it does not recover through rates (whether such non-recovery is because actual costs exceed authorized or forecast costs, the Utility did not seek authorization to recover certain costs, or the CPUC prohibited the Utility from recovering certain costs), the amount of third-party losses it is unable to recover through insurance, and the amount of penalties the Utility incurs in connection with the pending investigations and future citations for self-reported violations. After considering these impacts, the CPUC's interpretation of PG&E Corporation's obligation under the first priority condition could require PG&E Corporation to infuse the Utility with significant capital in the future or could prevent distributions from the Utility to PG&E Corporation, or both, any of which could materially restrict PG&E Corporation's ability to pay principal and interest on its outstanding debt or pay its common stock dividend, meet other obligations, or execute its business strategy. Further, laws or regulations could be enacted or adopted in the future that could impose additional financial or other restrictions or requirements pertaining to transactions between a holding company and its regulated subsidiaries.

**PG&E Corporation**
**CONS OLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| **Operating Revenues** | | | |
| Electric | $ 12,494 | $ 12,019 | $ 11,606 |
| Natural gas | 3,104 | 3,021 | 3,350 |
| **Total operating revenues** | **15,598** | **15,040** | **14,956** |
| **Operating Expenses** | | | |
| Cost of electricity | 5,016 | 4,162 | 4,016 |
| Cost of natural gas | 968 | 861 | 1,317 |
| Operating and maintenance | 5,775 | 6,052 | 5,466 |
| Depreciation, amortization, and decommissioning | 2,077 | 2,272 | 2,215 |
| **Total operating expenses** | **13,836** | **13,347** | **13,014** |
| **Operating Income** | 1,762 | 1,693 | 1,942 |
| Interest income | 9 | 7 | 7 |
| Interest expense | (715) | (703) | (700) |
| Other income, net | 40 | 70 | 49 |
| **Income Before Income Taxes** | **1,096** | **1,067** | **1,298** |
| Income tax provision | 268 | 237 | 440 |
| **Net Income** | **828** | **830** | **858** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 814** | **$ 816** | **$ 844** |
| **Weighted Average Common Shares Outstanding, Basic** | **444** | **424** | **401** |
| **Weighted Average Common Shares Outstanding, Diluted** | **445** | **425** | **402** |
| **Net Earnings Per Common Share, Basic** | **$ 1.83** | **$ 1.92** | **$ 2.10** |
| **Net Earnings Per Common Share, Diluted** | **$ 1.83** | **$ 1.92** | **$ 2.10** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONS OLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| (in millions) | Year ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|
| **Net Income** | **$ 828** | **$ 830** | **$ 858** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $80, $72, and $9, at respective dates) | 113 | 108 | (11) |
| Gain on investments (net of taxes of $26, $3, and $0, at respective dates) | 38 | 4 | - |
| **Total other comprehensive income (loss)** | **151** | **112** | **(11)** |
| **Comprehensive Income** | **979** | **942** | **847** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 965** | **$ 928** | **$ 833** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**C ON SOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 296 | $ 401 |
| Restricted cash | 301 | 330 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $80 and $87 at December 31, 2013 and 2012, respectively) | 1,091 | 937 |
| Accrued unbilled revenue | 766 | 761 |
| Regulatory balancing accounts | 1,124 | 936 |
| Other | 312 | 365 |
| Regulatory assets | 448 | 564 |
| Inventories | | |
| Gas stored underground and fuel oil | 137 | 135 |
| Materials and supplies | 317 | 309 |
| Income taxes receivable | 574 | 211 |
| Other | 611 | 172 |
| **Total current assets** | **5,977** | **5,121** |
| **Property, Plant, and Equipment** | | |
| Electric | 42,881 | 39,701 |
| Gas | 14,379 | 12,571 |
| Construction work in progress | 1,834 | 1,894 |
| Other | 2 | 1 |
| **Total property, plant, and equipment** | **59,096** | **54,167** |
| Accumulated depreciation | (17,844) | (16,644) |
| **Net property, plant, and equipment** | **41,252** | **37,523** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 4,913 | 6,809 |
| Nuclear decommissioning trusts | 2,342 | 2,161 |
| Income taxes receivable | 85 | 176 |
| Other | 1,036 | 659 |
| **Total other noncurrent assets** | **8,376** | **9,805** |
| **TOTAL ASSETS** | **$ 55,605** | **$ 52,449** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 1,174 | $ 492 |
| Long-term debt, classified as current | 889 | 400 |
| Accounts payable | | |
| Trade creditors | 1,293 | 1,241 |
| Disputed claims and customer refunds | 154 | 157 |
| Regulatory balancing accounts | 1,008 | 634 |
| Other | 471 | 444 |
| Interest payable | 892 | 870 |
| Other | 1,612 | 2,018 |
| **Total current liabilities** | **7,493** | **6,256** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 12,717 | 12,517 |
| Regulatory liabilities | 5,660 | 5,088 |
| Pension and other postretirement benefits | 1,601 | 3,575 |
| Asset retirement obligations | 3,539 | 2,919 |
| Deferred income taxes | 7,823 | 6,748 |
| Other | 2,178 | 2,020 |
| **Total noncurrent liabilities** | **33,518** | **32,867** |
| **Commitments and Contingencies (Note 14)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Preferred stock | - | - |
| Common stock, no par value, authorized 800,000,000 shares, 456,670,424 shares outstanding at December 31, 2013 and 430,718,293 shares outstanding at December 31, 2012 | 9,550 | 8,428 |
| Reinvested earnings | 4,742 | 4,747 |
| Accumulated other comprehensive income (loss) | 50 | (101) |
| **Total shareholders' equity** | **14,342** | **13,074** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **14,594** | **13,326** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 55,605** | **$ 52,449** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONS OLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 828 | $ 830 | $ 858 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,077 | 2,272 | 2,215 |
| Allowance for equity funds used during construction | (101) | (107) | (87) |
| Deferred income taxes and tax credits, net | 1,075 | 648 | 544 |
| PSEP disallowed capital expenditures | 196 | 353 | - |
| Other | 355 | 290 | 326 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (152) | (40) | (288) |
| Inventories | (10) | (24) | (63) |
| Accounts payable | 113 | (4) | 65 |
| Income taxes receivable/payable | (363) | (132) | (103) |
| Other current assets and liabilities | (469) | 262 | 23 |
| Regulatory assets, liabilities, and balancing accounts, net | (202) | 291 | (100) |
| Other noncurrent assets and liabilities | 80 | 243 | 349 |
| **Net cash provided by operating activities** | **3,427** | **4,882** | **3,739** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,207) | (4,624) | (4,038) |
| Decrease in restricted cash | 29 | 50 | 200 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,619 | 1,133 | 1,928 |
| Purchases of nuclear decommissioning trust investments | (1,604) | (1,189) | (1,963) |
| Other | 56 | 104 | (113) |
| **Net cash used in investing activities** | **(5,107)** | **(4,526)** | **(3,986)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings under revolving credit facilities | 140 | 120 | 358 |
| Repayments under revolving credit facilities | - | - | (358) |
| Net issuances (repayments) of commercial paper, net of discount of $2, $3, and $4 at respective dates | 542 | (1,021) | 782 |
| Proceeds from issuance of short-term debt | - | - | 250 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $18, $13, and $8 at respective dates | 1,532 | 1,137 | 792 |
| Short-term debt matured | - | (250) | (250) |
| Long-term debt matured or repurchased | (861) | (50) | (700) |
| Energy recovery bonds matured | - | (423) | (404) |
| Common stock issued | 1,045 | 751 | 662 |
| Common stock dividends paid | (782) | (746) | (704) |
| Other | (41) | 14 | 41 |
| **Net cash provided by (used in) financing activities** | **1,575** | **(468)** | **469** |
| **Net change in cash and cash equivalents** | **(105)** | **(112)** | **222** |
| **Cash and cash equivalents at January 1** | **401** | **513** | **291** |
| **Cash and cash equivalents at December 31** | **$ 296** | **$ 401** | **$ 513** |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (623) | $ (594) | $ (647) |
| Income taxes, net | (41) | 114 | (42) |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Common stock dividends declared but not yet paid | $ 208 | $ 196 | $ 188 |
| Capital expenditures financed through accounts payable | 322 | 362 | 308 |
| Noncash common stock issuances | 22 | 22 | 24 |
| Terminated capital leases | - | 136 | - |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Noncontrolling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2010** | **395,227,205** | **$ 6,878** | **$ 4,606** | **$ (202)** | **$ 11,282** | **$ 252** | **$ 11,534** |
| Net income | - | - | 858 | - | 858 | - | 858 |
| Other comprehensive loss | - | - | - | (11) | (11) | - | (11) |
| Common stock issued, net | 17,029,877 | 686 | - | - | 686 | - | 686 |
| Stock-based compensation amortization | - | 37 | - | - | 37 | - | 37 |
| Common stock dividends declared | - | - | (738) | - | (738) | - | (738) |
| Tax benefit from employee stock plans | - | 1 | - | - | 1 | - | 1 |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2011** | **412,257,082** | **7,602** | **4,712** | **(213)** | **12,101** | **252** | **12,353** |
| Net income | - | - | 830 | - | 830 | - | 830 |
| Other comprehensive income | - | - | - | 112 | 112 | - | 112 |
| Common stock issued, net | 18,461,211 | 773 | - | - | 773 | - | 773 |
| Stock-based compensation amortization | - | 52 | - | - | 52 | - | 52 |
| Common stock dividends declared | - | - | (781) | - | (781) | - | (781) |
| Tax benefit from employee stock plans | - | 1 | - | - | 1 | - | 1 |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2012** | **430,718,293** | **$ 8,428** | **$ 4,747** | **$ (101)** | **$ 13,074** | **$ 252** | **$ 13,326** |
| Net income | - | - | 828 | - | 828 | - | 828 |
| Other comprehensive income | - | - | - | 151 | 151 | - | 151 |
| Common stock issued, net | 25,952,131 | 1,067 | - | - | 1,067 | - | 1,067 |
| Stock-based compensation amortization | - | 56 | - | - | 56 | - | 56 |
| Common stock dividends declared | - | - | (819) | - | (819) | - | (819) |
| Tax expense from employee stock plans | - | (1) | - | - | (1) | - | (1) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2013** | **456,670,424** | **$ 9,550** | **$ 4,742** | **$ 50** | **$ 14,342** | **$ 252** | **$ 14,594** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONS OLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| **Operating Revenues** | | | |
| Electric | $ 12,489 | $ 12,014 | $ 11,601 |
| Natural gas | 3,104 | 3,021 | 3,350 |
| **Total operating revenues** | **15,593** | **15,035** | **14,951** |
| **Operating Expenses** | | | |
| Cost of electricity | 5,016 | 4,162 | 4,016 |
| Cost of natural gas | 968 | 861 | 1,317 |
| Operating and maintenance | 5,742 | 6,045 | 5,459 |
| Depreciation, amortization, and decommissioning | 2,077 | 2,272 | 2,215 |
| **Total operating expenses** | **13,803** | **13,340** | **13,007** |
| **Operating Income** | 1,790 | 1,695 | 1,944 |
| Interest income | 8 | 6 | 5 |
| Interest expense | (690) | (680) | (677) |
| Other income, net | 84 | 88 | 53 |
| **Income Before Income Taxes** | **1,192** | **1,109** | **1,325** |
| Income tax provision | 326 | 298 | 480 |
| **Net Income** | **866** | **811** | **845** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 852** | **$ 797** | **$ 831** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSO LIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2013** | **2012** | **2011** |
| **Net Income** | **$ 866** | **$ 811** | **$ 845** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $75, $73, and $4, at respective dates) | 106 | 109 | (7) |
| **Total other comprehensive income (loss)** | **106** | **109** | **(7)** |
| **Comprehensive Income** | **$ 972** | **$ 920** | **$ 838** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLI DATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 65 | $ 194 |
| Restricted cash | 301 | 330 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $80 and $87 at December 31, 2013 and 2012, respectively) | 1,091 | 937 |
| Accrued unbilled revenue | 766 | 761 |
| Regulatory balancing accounts | 1,124 | 936 |
| Other | 313 | 366 |
| Regulatory assets | 448 | 564 |
| Inventories | | |
| Gas stored underground and fuel oil | 137 | 135 |
| Materials and supplies | 317 | 309 |
| Income taxes receivable | 563 | 186 |
| Other | 523 | 160 |
| **Total current assets** | **5,648** | **4,878** |
| **Property, Plant, and Equipment** | | |
| Electric | 42,881 | 39,701 |
| Gas | 14,379 | 12,571 |
| Construction work in progress | 1,834 | 1,894 |
| **Total property, plant, and equipment** | **59,094** | **54,166** |
| Accumulated depreciation | (17,843) | (16,643) |
| **Net property, plant, and equipment** | **41,251** | **37,523** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 4,913 | 6,809 |
| Nuclear decommissioning trusts | 2,342 | 2,161 |
| Income taxes receivable | 81 | 171 |
| Other | 814 | 381 |
| **Total other noncurrent assets** | **8,150** | **9,522** |
| **TOTAL ASSETS** | **$ 55,049** | **$ 51,923** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2013** | **2012** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 914 | $ 372 |
| Long-term debt, classified as current | 539 | 400 |
| Accounts payable | | |
| Trade creditors | 1,293 | 1,241 |
| Disputed claims and customer refunds | 154 | 157 |
| Regulatory balancing accounts | 1,008 | 634 |
| Other | 432 | 419 |
| Interest payable | 887 | 865 |
| Other | 1,382 | 1,806 |
| **Total current liabilities** | **6,609** | **5,894** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 12,717 | 12,167 |
| Regulatory liabilities | 5,660 | 5,088 |
| Pension and other postretirement benefits | 1,530 | 3,497 |
| Asset retirement obligations | 3,539 | 2,919 |
| Deferred income taxes | 8,042 | 6,939 |
| Other | 2,111 | 1,959 |
| **Total noncurrent liabilities** | **33,599** | **32,569** |
| **Commitments and Contingencies (Note 14)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at December 31, 2013 and 2012 | 1,322 | 1,322 |
| Additional paid-in capital | 5,821 | 4,682 |
| Reinvested earnings | 7,427 | 7,291 |
| Accumulated other comprehensive income (loss) | 13 | (93) |
| **Total shareholders' equity** | **14,841** | **13,460** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 55,049** | **$ 51,923** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSO LIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 866 | $ 811 | $ 845 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,077 | 2,272 | 2,215 |
| Allowance for equity funds used during construction | (101) | (107) | (87) |
| Deferred income taxes and tax credits, net | 1,103 | 684 | 582 |
| PSEP disallowed capital expenditures | 196 | 353 | - |
| Other | 299 | 236 | 289 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (152) | (40) | (227) |
| Inventories | (10) | (24) | (63) |
| Accounts payable | 99 | (26) | 51 |
| Income taxes receivable/payable | (377) | (50) | (192) |
| Other current assets and liabilities | (404) | 272 | 36 |
| Regulatory assets, liabilities, and balancing accounts, net | (202) | 291 | (100) |
| Other noncurrent assets and liabilities | 22 | 256 | 414 |
| **Net cash provided by operating activities** | **3,416** | **4,928** | **3,763** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,207) | (4,624) | (4,038) |
| Decrease in restricted cash | 29 | 50 | 200 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,619 | 1,133 | 1,928 |
| Purchases of nuclear decommissioning trust investments | (1,604) | (1,189) | (1,963) |
| Other | 21 | 16 | 14 |
| **Net cash used in investing activities** | **(5,142)** | **(4,614)** | **(3,859)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings under revolving credit facilities | - | - | 208 |
| Repayments under revolving credit facilities | - | - | (208) |
| Net issuances (repayments) of commercial paper, net of discount of $2, $3, and $4 at respective dates | 542 | (1,021) | 782 |
| Proceeds from issuance of short-term debt | - | - | 250 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $18, $13, and $8 at respective dates | 1,532 | 1,137 | 792 |
| Short-term debt matured | - | (250) | (250) |
| Long-term debt matured or repurchased | (861) | (50) | (700) |
| Energy recovery bonds matured | - | (423) | (404) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution | 1,140 | 885 | 555 |
| Other | (26) | 28 | 54 |
| **Net cash provided by (used in) financing activities** | **1,597** | **(424)** | **349** |
| **Net change in cash and cash equivalents** | **(129)** | **(110)** | **253** |
| **Cash and cash equivalents at January 1** | **194** | **304** | **51** |
| **Cash and cash equivalents at December 31** | **$ 65** | **$ 194** | **$ 304** |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (600) | $ (574) | $ (627) |
| Income taxes, net | (62) | 174 | (50) |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Capital expenditures financed through accounts payable | $ 322 | $ 362 | $ 308 |
| Terminated capital leases | - | 136 | - |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONS OLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**
**(in millions)**

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2010** | **$ 258** | **$ 1,322** | **$ 3,241** | **$ 7,095** | **$ (195)** | **$ 11,721** |
| Net income | - | - | - | 845 | - | 845 |
| Other comprehensive loss | - | - | - | - | (7) | (7) |
| Equity contribution | - | - | 555 | - | - | 555 |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2011** | **258** | **1,322** | **3,796** | **7,210** | **(202)** | **12,384** |
| Net income | - | - | - | 811 | - | 811 |
| Other comprehensive income | - | - | - | - | 109 | 109 |
| Equity contribution | - | - | 885 | - | - | 885 |
| Tax benefit from employee stock plans | - | - | 1 | - | - | 1 |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2012** | **258** | **1,322** | **4,682** | **7,291** | **(93)** | **13,460** |
| Net income | - | - | - | 866 | - | 866 |
| Other comprehensive income | - | - | - | - | 106 | 106 |
| Equity contribution | - | - | 1,140 | - | - | 1,140 |
| Tax expense from employee stock plans | - | - | (1) | - | - | (1) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2013** | **$ 258** | **$ 1,322** | **$ 5,821** | **$ 7,427** | **$ 13** | **$ 14,841** |

See accompanying Notes to the Consolidated Financial Statements.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the Consolidated Financial Statements. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility operate in one segment.

The accompanying Consolidated Financial Statements have been prepared in accordance with GAAP and the instructions to Form 10-K and Regulation S-X promulgated by the SEC. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions, that are difficult to predict. Some of the more critical estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

### NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### Regulation and Regulated Operations

As a regulated entity, the Utility collects rates from customers to recover "revenue requirements" that have been authorized by the CPUC or the FERC based on the Utility's costs of service. The Utility's ability to recover a significant portion of its authorized revenue requirements through rates is independent, or "decoupled," from the volume of the Utility's electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

The Utility also records a regulatory balancing account asset or liability for differences between actual customer billings and authorized revenue requirements that are probable of recovery or refund. These differences do not have an impact on net income. The Utility also records differences between incurred costs and customer billings or authorized revenue meant to recover those costs. To the extent these differences are probable of recovery or refund, the Utility records a regulatory balancing account asset or liability, respectively, and the differences do not have an impact on net income. See "Revenue Recognition" below.

To the extent that portions of the Utility's operations cease to be subject to cost-of-service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable.

#### Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

#### Restricted Cash

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See Note 12 below.)

#### Allowance for Doubtful Accounts Receivable

Accounts receivable are primarily composed of trade receivables and unbilled revenue. PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

#### Inventories

Inventories are carried at weighted-average cost and include natural gas stored underground as well as materials and supplies. Natural gas stored underground represents gas that is recorded to inventory when purchased and then expensed as the gas is withdrawn for distribution to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and then expensed or capitalized to plant, as appropriate, when consumed or installed.

The Utility also purchases greenhouse gas emission allowances that are recorded as inventory. They are carried at weighted average cost and included in Other Noncurrent Assets – Other in the Consolidated Balance Sheets. The costs of the greenhouse gas emissions are expensed and recoverable through rates.

**Property, Plant, and Equipment**

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value. Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

| | Estimated Useful | Balance at December 31, | |
|---|---|---|---|
| **(in millions, except estimated useful lives)** | **Lives (years)** | **2013** | **2012** |
| Electricity generating facilities [1] | 20 to 100 | $ 9,116 | $ 8,253 |
| Electricity distribution facilities | 10 to 55 | 25,333 | 23,767 |
| Electricity transmission | 10 to 70 | 8,429 | 7,681 |
| Natural gas distribution facilities | 20 to 53 | 9,117 | 8,257 |
| Natural gas transportation and storage | 5 to 65 | 5,265 | 4,314 |
| Construction work in progress | | 1,834 | 1,894 |
| **Total property, plant, and equipment** | | **59,094** | **54,166** |
| Accumulated depreciation | | (17,843) | (16,643) |
| **Net property, plant, and equipment** | | **$ 41,251** | **$ 37,523** |

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 14 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.51% in 2013, 3.63% in 2012, and 3.67% in 2011. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $47 million and $101 million during 2013, $49 million and $107 million during 2012, and $40 million and $87 million during 2011.

**Asset Retirement Obligations**

PG&E Corporation and the Utility record an ARO at discounted fair value in the period in which the obligation is incurred if the discounted fair value can be reasonably estimated. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the ARO is accreted to its present value. PG&E Corporation and the Utility also record an ARO if a legal obligation to perform an asset removal exists and can be reasonably estimated, but performance is conditional upon a future event. The Utility recognizes timing differences between the recognition of costs and the costs recovered through the ratemaking process as regulatory assets or liabilities. (See Note 3 below.) The Utility has an ARO primarily for its nuclear generation facilities, certain fossil fuel-fired generation facilities, and gas transmission system assets.

For the year ended December 31, 2013, the Utility recorded an increase of $596 million to its ARO. The increase primarily reflects a higher expected cost per unit of transmission pipeline replacements.

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. In December 2012, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by $1.4 billion in 2012 due to higher spent nuclear fuel disposal costs and an increase in the scope of work. A significant portion of the increase in decommissioning cost estimates is due to the need to develop on-site storage for spent nuclear fuel because the federal government has failed to meet its obligation to develop a permanent repository for the disposal of nuclear waste from nuclear facilities in the United States. The Utility expects that it will recover its future on-site storage costs from the federal government. Recovered amounts will be refunded to customers through rates.

The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear generation facilities was approximately $3.5 billion at December 31, 2013 and 2012, as filed in the 2012 triennial proceeding. In future dollars, the estimated nuclear decommissioning cost is approximately $6.1 billion at December 31, 2013 and 2012. These estimates are based on the 2012 decommissioning cost studies and are prepared in accordance with CPUC requirements. The estimated nuclear decommissioning cost in future dollars is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $2.5 billion at December 31,

2013 and 2012.

A reconciliation of the changes in the ARO liability is as follows:

| **(in millions)** | | |
|---|---|---|
| ARO liability at December 31, 2011 | $ | 1,609 |
| Revision in estimated cash flows | | 1,301 |
| Accretion | | 101 |
| Liabilities settled | | (92) |
| ARO liability at December 31, 2012 | | **2,919** |
| Revision in estimated cash flows | | 596 |
| Accretion | | 130 |
| Liabilities settled | | (107) |
| **ARO liability at December 31, 2013** | **$** | **3,538** |

The Utility has identified the following AROs for which a reasonable estimate of fair value could not be made. As a result, the Utility has not recorded a liability related to these AROs:

- *Restoration of land to its pre-use condition under the terms of certain land rights agreements.* Land rights will be maintained for the foreseeable future, and therefore, the Utility cannot reasonably estimate the settlement date(s) or range of settlement dates for the obligations associated with these assets;

- *Removal and proper disposal of lead-based paint contained in some Utility facilities.* The Utility does not have information available that specifies which facilities contain lead-based paint and, therefore, cannot reasonably estimate the settlement date(s) associated with the obligations; and

- *Removal of certain communications equipment from leased property, and retirement activities associated with substation and certain hydroelectric facilities.* The Utility will maintain and continue to operate its hydroelectric facilities until the operation of a facility becomes uneconomical. The operation of the majority of the Utility's hydroelectric facilities is currently, and for the foreseeable future, expected to be economically beneficial. Therefore, the settlement date(s) cannot be reasonably estimated at this time.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. During 2013 and 2012, the Utility recorded charges of $196 million and $353 million, respectively, for PSEP capital costs that are expected to exceed the CPUC's authorized levels or that are specifically disallowed. (See "Natural Gas Matters" in Note 14 below). No material disallowance losses were recorded in 2011.

**Gains and Losses on Debt Extinguishments**

Deferred gains and losses on debt extinguishments are recorded to current assets – regulatory assets and other noncurrent assets – regulatory assets in the Consolidated Balance Sheets. Gains and losses on debt extinguishments associated with regulated operations are deferred and amortized over a period consistent with the recovery of costs through regulated rates. PG&E Corporation and the Utility recorded unamortized loss on debt extinguishments, net of gain, of $157 million, $163 million, and $186 million at December 31, 2013, 2012, and 2011, respectively. The amortization expense related to this loss was $23 million in both 2013 and 2012, and $18 million in 2011.

**Revenue Recognition**

The Utility recognizes revenues as electricity and natural gas services are delivered, and includes amounts for services rendered but not yet billed at the end of the period.

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three years. In general, the Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues once they have been authorized for rate recovery, amounts are objectively determinable and probable of recovery, and amounts are expected to be collected within 24 months. Generally, the revenue is recognized ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. Generally, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled.

The Utility's revenues and net income can be affected by incentive ratemaking mechanisms that adjust rates depending on the extent to which the Utility meets certain performance criteria.

**Income Taxes**

PG&E Corporation and the Utility use the liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense. (See Note 8 below.)

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period.

PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

**Nuclear Decommissioning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is known as the VIE's primary beneficiary and is required to consolidate the VIE. In determining whether consolidation of a particular entity is required, PG&E Corporation and the Utility first evaluate whether the entity is a VIE. If the entity is a VIE, PG&E Corporation and the Utility use a qualitative approach to determine if either is the primary beneficiary of the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2013, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial exposure is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2013, it did not consolidate any of them.

PG&E Corporation affiliates have entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that are considered VIEs. Under these agreements, PG&E Corporation has made cumulative lease payments and investment contributions of $362 million from 2010 to 2013 to these companies in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. At December 31, 2013 and 2012, the carrying amount of PG&E Corporation's investment in these agreements was $98 million and $166 million, respectively. PG&E Corporation has no material remaining commitment to fund these agreements. PG&E Corporation determined that it does not have control over the companies' significant economic activities, such as the design of the companies, vendor selection, construction, and the ongoing operations of the companies. Since PG&E Corporation was not the primary beneficiary of any of these VIEs at December 31, 2013, it did not consolidate any of them.

**Other Accounting Policies**

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies" in Note 14 of the Notes to the Consolidated Financial Statements.

**Adoption of New Accounting Pronouncements**

***Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income***

In February 2013, the Financial Accounting Standards Board issued an ASU that requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income. The ASU became effective for PG&E Corporation and the Utility on January 1, 2013.

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income for the year ended December 31, 2013 consisted of the following:

| (in millions) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| Beginning balance | $ (28) | $ (77) | $ 4 | $ (101) |
| Other comprehensive income before reclassifications: | | | | |
| Unrecognized net actuarial loss (net of taxes of $804, $35, and $0, respectively) | 1,169 | 45 | - | 1,214 |
| Transfer to regulatory account (net of taxes of $790, $22, and $0, respectively) | (1,150) | 31 | - | (1,119) |
| Gain on investments (net of taxes of $0, $0, and $26, respectively) | - | - | 38 | 38 |
| Amounts reclassified from other comprehensive income: (1) | | | | |
| Amortization of prior service cost (net of taxes of $8, $10, and $0, respectively) | 12 | 13 | - | 25 |
| Amortization of net actuarial loss (net of taxes of $45, $3, and $0, respectively) | 66 | 3 | - | 69 |
| Transfer to regulatory account (net of taxes of $54, $0, and $0, respectively) | (76) | - | - | (76) |
| **Net current period other comprehensive income** | **21** | **92** | **38** | **151** |
| **Ending balance** | **$ (7)** | **$ 15** | **$ 42** | **$ 50** |

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Disclosures about Offsetting Assets and Liabilities***

In January 2013, the Financial Accounting Standards Board issued an ASU that clarifies the scope of disclosures about offsetting assets and liabilities. The guidance requires an entity to disclose gross and net information about derivatives that are offset in the balance sheet or subject to an enforceable master-netting arrangement or similar agreement. The ASU became effective for PG&E Corporation and the Utility on January 1, 2013. (See Note 9 below.)

**NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS**

**Regulatory Assets**

Long-term regulatory assets are composed of the following:

| | Balance at December 31, | | Recovery |
|---|---|---|---|
| **(in millions)** | **2013** | **2012** | **Period** |
| Pension benefits [1] | $ 1,444 | $ 3,275 | N/A [4] |
| Deferred income taxes [1] | 1,835 | 1,627 | 1 - 45 years |
| Utility retained generation [2] | 503 | 552 | 11 years |
| Environmental compliance costs [1] | 628 | 604 | 32 years |
| Price risk management [1] | 106 | 210 | 9 years |
| Electromechanical meters [3] | 135 | 194 | 4 years |
| Unamortized loss, net of gain, on reacquired debt [1] | 135 | 141 | 13 years |
| Other | 127 | 206 | Various |
| **Total long-term regulatory assets** | **$ 4,913** | **$ 6,809** | |

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP and also includes amounts that otherwise would be recorded to accumulated other comprehensive loss in the Consolidated Balance Sheets. (See Note 11 below.)

(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.

(3) Represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices.

(4) The Utility expects to continuously recover pension benefits.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, regulatory assets for electromechanical meters, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

**Regulatory Liabilities**

Long-term regulatory liabilities are composed of the following:

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| Cost of removal obligations [1] | $ 3,844 | $ 3,625 |
| Recoveries in excess of AROs [2] | 748 | 620 |
| Public purpose programs [3] | 587 | 590 |
| Other | 481 | 253 |
| **Total long-term regulatory liabilities** | **$ 5,660** | **$ 5,088** |

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.

(2) Represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the Utility's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments. (See Note 10 below.)

(3) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

**Regulatory Balancing Accounts**

The Utility's recovery of a significant portion of revenue requirements and costs is decoupled from the volume of sales. The Utility records (1) differences between the Utility's authorized revenue requirement and actual customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility does not expect to collect or refund over the next 12 months are included in other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets.

The Utility sells and delivers electricity and natural gas, which includes procuring and generating electricity. The Utility also administers public purpose programs, primarily related to customer energy efficiency programs. The balancing accounts associated with these items will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are composed of the following:

| | Receivable Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| Electric distribution | $ 102 | $ 219 |
| Utility generation | 57 | 117 |
| Gas distribution | 70 | 44 |
| Energy procurement | 410 | 193 |
| Public purpose programs | 56 | 48 |
| Other | 429 | 315 |
| **Total regulatory balancing accounts receivable** | **$ 1,124** | **$ 936** |

| | Payable Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| Energy procurement | $ 298 | $ 116 |
| Public purpose programs | 171 | 131 |
| Other | 539 | 387 |
| **Total regulatory balancing accounts payable** | **$ 1,008** | **$ 634** |

**NOTE 4: DEBT**

**Long-Term Debt**

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

| | December 31, | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| **PG&E Corporation** | | |
| Senior notes, 5.75%, due 2014 | 350 | 350 |
| Less: current portion | (350) | - |
| **Total senior notes** | **-** | **350** |
| **Total PG&E Corporation long-term debt** | **-** | **350** |
| **Utility** | | |
| Senior notes: | | |
| 6.25% due 2013 | - | 400 |
| 4.80% due 2014 | 539 | 1,000 |
| 5.625% due 2017 | 700 | 700 |
| 8.25% due 2018 | 800 | 800 |
| 3.50% due 2020 | 800 | 800 |
| 4.25% due 2021 | 300 | 300 |
| 3.25% due 2021 | 250 | 250 |
| 2.45% due 2022 | 400 | 400 |
| 3.25% due 2023 | 375 | - |
| 3.85% due 2023 | 300 | - |
| 6.05% due 2034 | 3,000 | 3,000 |
| 5.80% due 2037 | 950 | 950 |
| 6.35% due 2038 | 400 | 400 |
| 6.25% due 2039 | 550 | 550 |
| 5.40% due 2040 | 800 | 800 |
| 4.50% due 2041 | 250 | 250 |
| 4.45% due 2042 | 400 | 400 |
| 3.75% due 2042 | 350 | 350 |
| 4.60% due 2043 | 375 | - |
| 5.125% due 2043 | 500 | - |
| Less: current portion | (539) | (400) |
| Unamortized discount, net of premium | (51) | (51) |
| **Total senior notes, net of current portion** | **11,449** | **10,899** |
| Pollution control bonds: | | |
| Series 1996 C, E, F, 1997 B, variable rates (1), due 2026 (2) | 614 | 614 |
| Series 2004 A-D, 4.75%, due 2023 (3) | 345 | 345 |
| Series 2009 A-D, variable rates (4), due 2016 and 2026 (5) | 309 | 309 |
| **Total pollution control bonds** | **1,268** | **1,268** |
| **Total Utility long-term debt, net of current portion** | **12,717** | **12,167** |
| **Total consolidated long-term debt, net of current portion** | **$ 12,717** | **$ 12,517** |

(1) At December 31, 2013, interest rates on these bonds and the related loans ranged from 0.01% to 0.04%.

(2) Each series of these bonds is supported by a separate letter of credit. In April 2013, the letters of credit were extended to April 1, 2018. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(3) The Utility has obtained credit support from an insurance company for these bonds.

(4) At December 31, 2013, interest rates on these bonds and the related loans ranged from 0.01% to 0.02%.

(5) Each series of these bonds is supported by a separate direct-pay letter of credit. Series A and B letters of credit expire on May 31, 2016. In October 2013, Series C and D letters of credit were extended to December 3, 2016 to coincide with the maturity of the underlying bonds. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

**Repayment Schedule**

PG&E Corporation's and the Utility's combined short-term and long-term debt principal repayment amounts at December 31, 2013 are reflected in the table below:

| (in millions, except interest rates) | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest rate | 5.75% | - | - | - | - | - | 5.75% |
| Fixed rate obligations | $ 350 | $ - | $ - | $ - | $ - | $ - | $ 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | 4.80% | - | - | 5.63% | 8.25% | 5.06% | 5.29% |
| Fixed rate obligations | $ 539 | $ - | $ - | $ 700 | $ 800 | $ 10,345 | $ 12,384 |
| Variable interest rate as of December 31, 2013 | - | - | 0.02% | - | 0.02% | - | 0.02% |
| Variable rate obligations (1) | $ - | $ - | $ 309 | $ - | $ 614 | $ - | $ 923 |
| **Total consolidated debt** | **$ 889** | **$ -** | **$ 309** | **$ 700** | **$ 1,414** | **$ 10,345** | **$ 13,657** |

(1) These bonds, due in 2016 and 2026, are backed by separate letters of credit that expire on May 31, 2016, December 3, 2016, or April 1, 2018.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and the Utility's commercial paper program at December 31, 2013:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Borrowings | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|---|
| PG&E Corporation | April 2018 | $ 300(1) | $ - | $ 260 | $ - | $ 40 |
| Utility | April 2018 | 3,000(2) | 79 | - | 914(3) | 2,007(3) |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 79** | **$ 260** | **$ 914** | **$ 2,047** |

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
(3) The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2013, the average outstanding borrowings on PG&E Corporation's revolving credit facility was $214 million and the maximum outstanding balance during the year was $260 million. For 2013, the Utility's average outstanding commercial paper balance was $542 million and the maximum outstanding balance during the year was $1.1 billion. The Utility did not borrow under its credit facility in 2013.

***Revolving Credit Facilities***

In April 2013, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from May 31, 2016 to April 1, 2018. These agreements contain substantially similar terms as their original 2011 credit agreements. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for additional periods. Provided certain conditions are met, PG&E Corporation and the Utility have the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the revolving credit facilities by up to $100 million and $500 million, respectively, in the aggregate for all such increases.

Borrowings under the revolving credit facilities (other than swingline loans) bear interest based, at PG&E Corporation's and the Utility's election, on (1) a London Interbank Offered Rate plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the federal funds rate, or the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. PG&E Corporation and the Utility also will pay a facility fee on the total commitments of the lenders under the revolving credit facilities. The applicable margins and the facility fees will be based on PG&E Corporation's and the Utility's senior unsecured debt ratings issued by Standard & Poor's Rating Services and Moody's Investor Service. Facility fees are payable quarterly in arrears.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility.

***Commercial Paper Programs***

At December 31, 2013, the average yield on outstanding Utility commercial paper was 0.26%.

In January 2014, PG&E Corporation established a commercial paper program. PG&E Corporation will treat the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

The borrowings from PG&E Corporation and the Utility's commercial paper programs are used primarily to fund temporary financing needs. Liquidity support for these borrowings is provided by available capacity under their respective revolving credit facilities, as described above. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation's and the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

**NOTE 5 : COMMON STOCK AND SHARE-BASED COMPENSATION**

PG&E Corporation had 456,670,424 shares of common stock outstanding at December 31, 2013. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2013.

In May 2013, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $400 million. As of December 31, 2013, PG&E Corporation had old common stock having an aggregate gross sales price of $395 million and had the ability to issue an additional $5 million of its common stock under this agreement. During 2013, PG&E Corporation paid commissions of $3 million under this agreement.

During 2013, PG&E Corporation issued 26 million shares of its common stock for aggregate net cash proceeds of $1,045 million in the following transactions:

- 7 million shares were sold in an underwritten public offering for cash proceeds of $300 million, net of fees and commissions;
- 8 million shares were issued for cash proceeds of $290 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and
- 11 million shares were sold for cash proceeds of $455 million, net of commissions paid of $4 million, under equity distribution agreements.

**Dividends**

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. For 2013, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of $0.455 per share.

Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio, $493 million of the Utility's reinvested earnings was restricted at December 31, 2013. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average. At December 31, 2013, the Utility was required to maintain reinvested earnings of $7.4 billion as equity to meet this requirement.

In addition, to comply with the revolving credit facility's 65% ratio requirement and the CPUC's requirement to maintain a 52% equity component, $7.7 billion and $14.6 billion of the Utility's net assets were restricted at December 31, 2013 to comply with these requirements, respectively, and could not be transferred to PG&E Corporation in the form of cash dividends. As a holding company, PG&E Corporation depends on cash distributions from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

**Long-Term Incentive Plan**

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including stock options, stock appreciation rights, restricted stock awards, RSUs, performance shares, deferred compensation awards, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) has been reserved for issuance under the 2006 LTIP, of which 3,310,474 shares were available for future awards at December 31, 2013.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2013, 2012, and 2011:

| **(in millions)** | | **2013** | | **2012** | | **2011** |
|---|---|---|---|---|---|---|
| Restricted stock units | $ | 36 | $ | 31 | $ | 23 |
| Performance shares: | | | | | | |
| Equity awards | | 28 | | 26 | | 16 |
| Liability awards | | - | | - | | (13) |
| Total compensation expense (pre-tax) | **$** | **64** | **$** | **57** | **$** | **26** |
| Total compensation expense (after-tax) | **$** | **38** | **$** | **34** | **$** | **16** |

Share-based compensation costs capitalized during 2013, 2012, and 2011 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

RSU awards issued and outstanding under the LTIP generally vest over three year periods. RSUs generally vest in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Vested RSUs are settled in shares of PG&E Corporation common stock. Additionally, upon settlement, RSU recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant. RSU expense is generally recognized ratably over the vesting period based on the fair values determined. The weighted average grant-date fair value for RSUs granted during 2013, 2012, and 2011 was $42.92, $42.17, and $45.10, respectively. The total fair value of RSUs that vested during 2013, 2012, and 2011 was $30 million, $18 million, and $11 million, respectively. The tax benefit from RSUs that vested during each period was not material. As of December 31, 2013, $50 million of total unrecognized compensation costs related to nonvested RSUs was expected to be recognized over the remaining weighted average period of 2.17 years.

The following table summarizes RSU activity for 2013:

| | **Number of Restricted Stock Units** | | **Weighted Average Grant-Date Fair Value** |
|---|---|---|---|
| Nonvested at January 1 | 2,069,291 | $ | 42.52 |
| Granted | 993,115 | $ | 42.92 |
| Vested | (719,071) | $ | 41.03 |
| Forfeited | (43,314) | $ | 42.68 |
| Nonvested at December 31 | **2,300,021** | $ | 43.16 |

***Performance Shares***

Performance shares awarded to recipients under the LTIP are for a specified number of shares of common stock (or cash with respect to grants before 2010) based on PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period. Performance shares vest after three years of service. Performance share expense is generally recognized ratably over the applicable three-year period based on the fair values determined. Dividend equivalents on performance shares, if any, will be paid in cash upon the vesting date based on the amount of common stock to which the recipients are entitled.

Total compensation expense for performance shares is based on the grant-date fair value, which is determined using a Monte Carlo simulation valuation model. The weighted average grant-date fair value for performance shares granted during 2013, 2012, and 2011 was $33.45, $41.93, and $33.91 respectively. There was no tax benefit associated with performance shares that vested during each of these periods. As of December 31, 2013, $29 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted average period of 1.25 years.

The following table summarizes performance shares classified as equity awards activity for 2013:

| | **Number of Performance Shares** | | **Weighted Average Grant-Date Fair Value** |
|---|---|---|---|
| Nonvested at January 1 | 1,497,473 | $ | 38.15 |
| Granted | 911,620 | $ | 33.45 |
| Vested | - | $ | - |
| Forfeited [(1)] | (617,773) | $ | 34.22 |
| Nonvested at December 31 | **1,791,320** | $ | 37.85 |

(1) Includes performance shares that expired with zero value as performance targets were not met.

**NOTE 6 : PREFERRED STOCK**

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. The Utility specifies that 5,784,825 shares of the $25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. The following table summarizes the Utility's outstanding preferred stock, none of which had mandatory redemption provisions at December 31, 2013 and 2012:

| **(in millions, except share amounts, redemption price, and par value)** | **Shares Outstanding** | **Redemption Price** | **Balance** |
|---|---|---|---|
| **Nonredeemable $25 par value preferred stock** | | | |
| 5.00% Series | 400,000 | N/A | $ 10 |
| 5.50% Series | 1,173,163 | N/A | 30 |
| 6.00% Series | 4,211,662 | N/A | 105 |
| **Total nonredeemable preferred stock** | **5,784,825** | | **$ 145** |
| | | | |
| **Redeemable $25 par value preferred stock** | | | |
| 4.36% Series | 418,291 | $ 25.75 | $ 11 |
| 4.50% Series | 611,142 | 26.00 | 15 |
| 4.80% Series | 793,031 | 27.25 | 20 |
| 5.00% Series | 1,778,172 | 26.75 | 44 |
| 5.00% Series A | 934,322 | 26.75 | 23 |
| **Total redeemable preferred stock** | **4,534,958** | | **$ 113** |
| **Preferred stock** | | | **$ 258** |

At December 31, 2013, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2013, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. During each of 2013, 2012, and 2011 the Utility paid $14 million of dividends on preferred stock.

## NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2013, 2012 and 2011.

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2013** | **2012** | **2011** |
| **Income available for common shareholders** | $ 814 | $ 816 | $ 844 |
| **Weighted average common shares outstanding, basic** | 444 | 424 | 401 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | 1 | 1 | 1 |
| **Weighted average common share outstanding, diluted** | 445 | 425 | 402 |
| **Total earnings per common share, diluted** | **$ 1.83** | **$ 1.92** | **$ 2.10** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

## NOTE 8 : INCOME TAXES

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| **(in millions)** | **2013** | **2012** | **2011** | **2013** | **2012** | **2011** |
| Current: | | | | | | |
| Federal | $ (218) | $ (74) | $ (77) | $ (222) | $ (52) | $ (83) |
| State | (26) | 33 | 152 | (23) | 41 | 161 |
| Deferred: | | | | | | |
| Federal | 552 | 374 | 504 | 604 | 404 | 534 |
| State | (35) | (92) | (135) | (28) | (91) | (128) |
| Tax credits | (5) | (4) | (4) | (5) | (4) | (4) |
| **Income tax provision** | **$ 268** | **$ 237** | **$ 440** | **$ 326** | **$ 298** | **$ 480** |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| **(in millions)** | **2013** | **2012** | **2013** | **2012** |
| **Deferred income tax assets:** | | | | |
| Customer advances for construction | $ 90 | $ 101 | $ 90 | $ 101 |
| Reserve for damages | 161 | 175 | 161 | 175 |
| Environmental reserve | 152 | 97 | 152 | 97 |
| Compensation | 167 | 229 | 102 | 179 |
| Net operating loss carryforward | 890 | 938 | 670 | 736 |
| GHG allowances | 108 | 34 | 108 | 34 |
| Other | 135 | 230 | 128 | 221 |
| **Total deferred income tax assets** | **$ 1,703** | **$ 1,804** | **$ 1,411** | **$ 1,543** |
| **Deferred income tax liabilities:** | | | | |
| Regulatory balancing accounts | $ 261 | $ 256 | $ 261 | $ 256 |
| Property related basis differences | 8,048 | 7,449 | 8,038 | 7,447 |
| Income tax regulatory asset | 748 | 663 | 748 | 663 |
| Other | 151 | 173 | 86 | 99 |
| **Total deferred income tax liabilities** | **$ 9,208** | **$ 8,541** | **$ 9,133** | **$ 8,465** |
| **Total net deferred income tax liabilities** | **$ 7,505** | **$ 6,737** | **$ 7,722** | **$ 6,922** |
| **Classification of net deferred income tax liabilities:** | | | | |
| Included in current liabilities (assets) | $ (318) | $ (11) | $ (320) | $ (17) |
| Included in noncurrent liabilities | 7,823 | 6,748 | 8,042 | 6,939 |
| **Total net deferred income tax liabilities** | **$ 7,505** | **$ 6,737** | **$ 7,722** | **$ 6,922** |

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| | **2013** | **2012** | **2011** | **2013** | **2012** | **2011** |
| Federal statutory income tax rate | 35.0% | 35.0% | 35.0% | 35.0% | 35.0% | 35.0% |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) | (3.1) | (3.9) | 1.1 | (2.2) | (3.0) | 1.6 |
| Effect of regulatory treatment of fixed asset differences | (4.2) | (4.1) | (4.4) | (3.8) | (3.9) | (4.2) |
| Tax credits | (0.4) | (0.6) | (0.5) | (0.4) | (0.6) | (0.5) |
| Benefit of loss carryback | (1.1) | (0.7) | (1.9) | (1.0) | (0.4) | (2.1) |
| Non deductible penalties | 0.8 | 0.6 | 6.5 | 0.7 | 0.5 | 6.3 |
| Other, net | (2.2) | (3.8) | (1.5) | (0.9) | (0.8) | 0.1 |
| **Effective tax rate** | **24.8%** | **22.5%** | **34.3%** | **27.4%** | **26.8%** | **36.2%** |

***Unrecognized tax benefits***

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2013** | **2012** | **2011** |
| **(in millions)** | | | | | | |
| **Balance at beginning of year** | $ 581 | $ 506 | $ 714 | $ 575 | $ 503 | $ 712 |
| Additions for tax position taken during a prior year | 12 | 32 | 2 | 12 | 26 | 2 |
| Reductions for tax position taken during a prior year | (6) | (13) | (198) | (6) | (10) | (196) |
| Additions for tax position taken during the current year | 79 | 67 | 3 | 79 | 67 | - |
| Settlements | - | (11) | (15) | - | (11) | (15) |
| **Balance at end of year** | **$ 666** | **$ 581** | **$ 506** | **$ 660** | **$ 575** | **$ 503** |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2013 for PG&E Corporation and the Utility was $29 million, with the remaining balance representing the potential deferral of taxes to later years.

***Tax settlements and years that remain subject to examination***

PG&E Corporation participates in the Compliance Assurance Process, a real-time IRS audit intended to expedite resolution of tax matters. The Compliance Assurance Process audit culminates with a letter from the IRS indicating its acceptance of the return.

In January 2014, PG&E Corporation received the IRS closing agreements for the 2008 and 2010 audit years, subject to the approval by the Joint Committee on Taxation of the U.S. Congress. The IRS has previously accepted the 2009 tax return without adjustments. The IRS is currently reviewing several matters pertaining to the 2011 and 2012 tax returns. The most significant of these matters relates to the repairs accounting method changes.

The IRS has been working with the utility industry to provide guidance concerning the deductibility of repairs. PG&E Corporation and the Utility expect the IRS to issue guidance with respect to repairs made in the natural gas transmission and distribution businesses during 2014. PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the guidance to be issued by the IRS and the resolution of the IRS audits related to the 2010, 2011, and 2012 tax returns. As of December 31, 2013, PG&E Corporation and the Utility believe that it is reasonably possible that unrecognized tax benefits will decrease by approximately $350 million within the next 12 months.

*Carryforwards*

As of December 31, 2013, PG&E Corporation had approximately $3.3 billion of federal net operating loss carryforwards and $68 million of tax credit carryforwards, which will expire between 2029 and 2033. In addition, PG&E Corporation had approximately $121 million of loss carryforwards related to charitable contributions, which will expire between 2014 and 2018. PG&E Corporation believes it is more likely than not the tax benefits associated with the federal operating loss, charitable contributions, and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2013. As of December 31, 2013, PG&E Corporation had approximately $15 million of federal net operating loss carryforwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

## NOTE 9 : DERIVATIVES

### Use of Derivative Instruments

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including forward contracts, swap agreements, futures contracts, and option contracts.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. As long as the current ratemaking mechanism discussed above remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives, the Utility expects to recover fully, in rates, all costs related to derivatives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

PG&E Corporation and the Utility offset cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement where the right of offset and the intention to offset exist.

The Utility elects the normal purchase and sale exception for eligible derivatives. Derivatives that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered are eligible for the normal purchase and sale exception. The fair value of derivatives that are eligible for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets at fair value, but are accounted for under the accrual method of accounting. Therefore, expenses are recognized as incurred.

*Electricity Procurement*

The Utility enters into third-party power purchase agreements for electricity to meet customer needs. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivatives. The Utility elects the normal purchase and sale exception for eligible derivatives.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce volatility in customer rates, the Utility may enter into financial instruments, such as futures, options, or swaps, to effectively fix and/or cap the price of future purchases and reduce cash flow variability associated with fluctuating electricity prices. These financial contracts are considered derivatives.

*Electric Transmission Congestion Revenue Rights*

The California electric transmission grid, controlled by the CAISO, is subject to transmission constraints when there is insufficient transmission capacity to supply the market. The CAISO imposes congestion charges on market participants to manage transmission congestion. The revenue generated from congestion charges is allocated to holders of CRRs. CRRs allow market participants to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load-serving entities, such as the Utility, are allocated CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (in which CRRs are priced at market and available to all market participants). The Utility can participate in the allocation and auction phases of the annual and monthly CRR processes. CRRs are considered derivatives.

*Natural Gas Procurement (Electric Fuels Portfolio)*

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through physical natural gas commodity purchases to fuel natural gas generating facilities, and electricity procurement contracts indexed to natural gas prices. To reduce the volatility in customer rates, the Utility may enter into financial instruments, such as futures, options, or swaps. The Utility also enters into fixed-price forward contracts for natural gas to reduce future cash flow variability from fluctuating natural gas prices. These instruments are considered derivatives.

***Natural Gas Procurement (Core Gas Supply Portfolio)***

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its residential and smaller commercial customers known as “core” customers. The Utility does not procure natural gas for industrial and large commercial, or “non-core,” customers. Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of natural gas may be purchased or sold in the multi-month, monthly, and to a lesser extent, daily spot market to balance such seasonal supply and demand. The Utility purchases financial instruments, such as futures, swaps and options, as part of its core winter hedging program in order to manage customer exposure to high natural gas prices during peak winter months. These financial instruments are considered derivatives.

**Volume of Derivative Activity**

At December 31, 2013, the volumes of PG&E Corporation’s and the Utility’s outstanding derivatives were as follows:

| | | Contract Volume (1) | | | |
|---|---|---|---|---|---|
| **Underlying Product** | **Instruments** | **Less Than 1 Year** | **1 Year or Greater but Less Than 3 Years** | **3 Years or Greater but Less Than 5 Years** | **5 Years or Greater (2)** |
| Natural Gas (3) (MMBtus (4) ) | Forwards and Swaps | 243,213,288 | 79,735,000 | 8,892,500 | - |
| | Options | 169,123,208 | 87,689,708 | 3,450,000 | - |
| Electricity (Megawatt-hours) | Forwards and Swaps | 2,537,023 | 2,009,505 | 2,008,046 | 1,534,695 |
| | Congestion Revenue Rights | 73,510,440 | 83,747,782 | 63,718,517 | 29,945,852 |

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.

(2) Derivatives in this category expire between 2019 and 2022.

(3) Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

(4) Million British Thermal Units.

At December 31, 2012, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

| | | Contract Volume [1] | | | |
|---|---|---|---|---|---|
| Underlying Product | Instruments | Less Than 1 Year | 1 Year or Greater but Less Than 3 Years | 3 Years or Greater but Less Than 5 Years | 5 Years or Greater [2] |
| Natural Gas [3] (MMBtus [4]) | Forwards and Swaps | 329,466,510 | 98,628,398 | 5,490,000 | - |
| | Options | 221,587,431 | 216,279,767 | 10,050,000 | - |
| Electricity (Megawatt-hours) | Forwards and Swaps | 2,537,023 | 3,541,046 | 2,009,505 | 2,538,718 |
| | Options | - | 239,015 | 239,233 | 119,508 |
| | Congestion Revenue Rights | 74,198,690 | 74,187,803 | 74,240,147 | 25,699,804 |

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.

(2) Derivatives in this category expire between 2018 and 2023.

(3) Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

(4) Million British Thermal Units .

**Presentation of Derivative Instruments in the Financial Statements**

In PG&E Corporation's and the Utility's Consolidated Balance Sheets, derivatives are presented on a net basis by counterparty where the right and the intention to offset exists under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At December 31, 2013, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 42 | $ (10) | $ 16 | $ 48 |
| Other noncurrent assets – other | 99 | (4) | - | 95 |
| Current liabilities – other | (122) | 10 | 69 | (43) |
| Noncurrent liabilities – other | (110) | 4 | 2 | (104) |
| **Total commodity risk** | **$ (91)** | **$ -** | **$ 87** | **$ (4)** |

At December 31, 2012, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 48 | $ (25) | $ 36 | $ 59 |
| Other noncurrent assets – other | 99 | (11) | - | 88 |
| Current liabilities – other | (255) | 25 | 115 | (115) |
| Noncurrent liabilities – other | (221) | 11 | 14 | (196) |
| **Total commodity risk** | **$ (329)** | **$ -** | **$ 165** | **$ (164)** |

Gains and losses recorded on PG&E Corporation's and the Utility's derivatives were as follows:

| (in millions) | Commodity Risk — For the year ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|
| Unrealized gain/(loss) - regulatory assets and liabilities [1] | $ 238 | $ 391 | $ 21 |
| Realized loss - cost of electricity [2] | (178) | (486) | (558) |
| Realized loss - cost of natural gas [2] | (22) | (38) | (106) |
| **Total commodity risk** | **$ 38** | **$ (133)** | **$ (643)** |

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2013, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| (in millions) | Balance at December 31, 2013 | 2012 |
|---|---|---|
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (79) | $ (266) |
| Related derivatives in an asset position | 4 | 59 |
| Collateral posting in the normal course of business related to these derivatives | 65 | 103 |
| **Net position of derivative contracts/additional collateral posting requirements [1]** | **$ (10)** | **$ (104)** |

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

**NOTE 10 : FAIR VALUE MEASUREMENTS**

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts and other investments are held by PG&E Corporation and not the Utility):

| | Fair Value Measurements At December 31, 2013 | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Netting [1]** | **Total** |
| **Assets:** | | | | | |
| Money market investments | $ 226 | $ - | $ - | $ - | **$ 226** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 38 | - | - | - | **38** |
| U.S. equity securities | 1,046 | 11 | | - | **1,057** |
| Non-U.S. equity securities | 457 | - | - | - | **457** |
| U.S. government and agency securities | 760 | 156 | - | - | **916** |
| Municipal securities | - | 25 | - | - | **25** |
| Other fixed-income securities | - | 162 | - | - | **162** |
| Total nuclear decommissioning trusts [2] | **2,301** | **354** | **-** | **-** | **2,655** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 2 | 27 | 107 | 3 | **139** |
| Gas | - | 5 | - | (1) | **4** |
| Total price risk management instruments | **2** | **32** | **107** | **2** | **143** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 39 | - | - | **39** |
| Life insurance contracts | - | 70 | - | - | **70** |
| Total rabbi trusts | **-** | **109** | **-** | **-** | **109** |
| Long-term disability trust | | | | | |
| Money market investments | 9 | - | - | - | **9** |
| U.S. equity securities | - | 14 | - | - | **14** |
| Non-U.S. equity securities | - | 12 | - | - | **12** |
| Fixed-income securities | - | 122 | - | - | **122** |
| Total long-term disability trust | 9 | 148 | - | - | **157** |
| Other investments | 84 | - | - | - | **84** |
| **Total assets** | **$ 2,622** | **$ 643** | **$ 107** | **$ 2** | **$ 3,374** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 19 | $ 72 | $ 137 | $ (84) | **$ 144** |
| Gas | 1 | 3 | - | (1) | **3** |
| **Total liabilities** | **$ 20** | **$ 75** | **$ 137** | **$ (85)** | **$ 147** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $313 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2012 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Money market investments | $ 209 | $ - | $ - | $ - | **$ 209** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 21 | - | - | - | **21** |
| U.S. equity securities | 940 | 9 | - | - | **949** |
| Non-U.S. equity securities | 379 | - | - | - | **379** |
| U.S. government and agency securities | 681 | 139 | - | - | **820** |
| Municipal securities | - | 59 | - | - | **59** |
| Other fixed-income securities | - | 173 | - | - | **173** |
| Total nuclear decommissioning trusts [2] | **2,021** | **380** | **-** | **-** | **2,401** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 1 | 60 | 80 | 6 | **147** |
| Gas | - | 5 | 1 | (6) | **-** |
| Total price risk management instruments | **1** | **65** | **81** | **-** | **147** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 30 | - | - | **30** |
| Life insurance contracts | - | 72 | - | - | **72** |
| Total rabbi trusts | **-** | **102** | **-** | **-** | **102** |
| Long-term disability trust | | | | | |
| Money market investments | 10 | - | - | - | **10** |
| U.S. equity securities | - | 14 | - | - | **14** |
| Non-U.S. equity securities | - | 11 | - | - | **11** |
| Fixed-income securities | - | 136 | - | - | **136** |
| Total long-term disability trust | **10** | **161** | **-** | **-** | **171** |
| **Total assets** | **$ 2,241** | **$ 708** | **$ 81** | **$ -** | **$ 3,030** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 155 | $ 144 | $ 160 | $ (156) | **$ 303** |
| Gas | 8 | 9 | - | (9) | **8** |
| **Total liabilities** | **$ 163** | **$ 153** | **$ 160** | **$ (165)** | **$ 311** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

[2] Represents amount before deducting $240 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days.

***Money Market Investments***

PG&E Corporation and the Utility invest in money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as U.S. Treasury bills, U.S. agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's and the Utility's investments in these money market funds are valued using unadjusted prices for identical assets in an active market and are thus classified as Level 1. Money market funds are recorded as cash and cash equivalents in the Consolidated Balance Sheets.

***Trust Assets***

The assets held by the nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity securities primarily include investments in common stock, which are valued based on unadjusted prices for identical securities in active markets and are classified as Level 1. Equity securities also include commingled funds, that are valued using a net asset value per share and are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world and are classified as Level 2. Price quotes for the assets held by these funds are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2. Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are valued based on prices observed in the CAISO auction, which are discounted at the risk-free rate. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions. CRRs are classified as Level 3.

***Other Investments***

Other investments in common stock are valued based on unadjusted prices for the investments and are actively traded on public exchanges. These investments are therefore considered Level 1 assets.

**Transfers between Levels**

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. For the years ended December 31, 2013 and 2012, there were no significant transfers between levels.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Risk Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments. These models use pricing inputs from brokers and historical data. The market and credit risk management function and the Utility's finance function collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

CRRs and power purchase agreements are valued using historical prices or significant unobservable inputs derived from internally developed models. Historical prices include CRR auction prices. Unobservable inputs include forward electricity prices. Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

| (in millions) | Fair Value at December 31, 2013 | | | | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Valuation Technique** | **Unobservable Input** | **Range [1]** |
| Congestion revenue rights | $ 107 | $ 32 | Market approach | CRR auction prices | (6.47) - $12.04 |
| Power purchase agreements | $ - | $ 105 | Discounted cash flow | Forward prices | $23.43 - 51.75 |

(1) Represents price per megawatt-hour

| (in millions) | Fair Value at December 31, 2012 | | | | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Valuation Technique** | **Unobservable Input** | **Range [1]** |
| Congestion revenue rights | $ 80 | $ 16 | Market approach | CRR auction prices | (9.04) - $55.15 |
| Power purchase agreements | $ - | $ 145 | Discounted cash flow | Forward prices | $8.59 - 62.90 |

(1) Represents price per megawatt-hour

**Level 3 Reconciliation**

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2013 and 2012, respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| Liability balance as of January 1 | **$ (79)** | **$ (74)** |
| Realized and unrealized gains (losses): | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | 49 | (5) |
| **Liability balance as of December 31** | **$ (30)** | **$ (79)** |

(1)The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

### Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2013 and 2012, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2013 and 2012.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2013 | | 2012 | |
| (in millions) | Carrying Amount | Level 2 Fair Value | Carrying Amount | Level 2 Fair Value |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 350 | $ 354 | $ 349 | $ 371 |
| Utility | 12,334 | 13,444 | 11,645 | 13,946 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| **As of December 31, 2013** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 38 | $ - | $ - | $ 38 |
| Equity securities | | | | |
| U.S. | 246 | 811 | - | 1,057 |
| Non-U.S. | 215 | 242 | - | 457 |
| Debt securities | | | | |
| U.S. government and agency securities | 870 | 51 | (5) | 916 |
| Municipal securities | 24 | 2 | (1) | 25 |
| Other fixed-income securities | 163 | 1 | (2) | 162 |
| Total nuclear decommissioning trusts (1) | 1,556 | 1,107 | (8) | 2,655 |
| Other investments | 13 | 71 | - | 84 |
| **Total** | **$ 1,569** | **$ 1,178** | **$ (8)** | **$ 2,739** |
| **As of December 31, 2012** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 21 | $ - | $ - | $ 21 |
| Equity securities | | | | |
| U.S. | 331 | 618 | - | 949 |
| Non-U.S. | 199 | 181 | (1) | 379 |
| Debt securities | | | | |
| U.S. government and agency securities | 723 | 97 | - | 820 |
| Municipal securities | 56 | 4 | (1) | 59 |
| Other fixed-income securities | 168 | 5 | - | 173 |
| **Total (1)** | **$ 1,498** | **$ 905** | **$ (2)** | **$ 2,401** |

(1) Represents amounts before deducting $313 million and $240 million at December 31, 2013 and 2012, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

| **(in millions)** | **As of December 31, 2013** |
|---|---|
| Less than 1 year | $ 22 |
| 1–5 years | 519 |
| 5–10 years | 230 |
| More than 10 years | 332 |
| **Total maturities of debt securities** | **$ 1,103** |

The following table provides a summary of activity for the debt and equity securities:

| **(in millions)** | **2013** | **2012** | **2011** |
|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 1,619 | $ 1,133 | $ 1,928 |
| Gross realized gains on sales of securities held as available-for-sale | 94 | 19 | 43 |
| Gross realized losses on sales of securities held as available-for-sale | (13) | (17) | (30) |

## NOTE 11 : EMPLOYEE BENEFIT PLANS

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees, as well as contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Additionally, eligible employees hired after December 31, 2012 participate in the cash balance plan that was added to the defined benefit pension plan in 2012. Eligible employees hired before December 31, 2012 were given a one-time election to participate in the cash balance plan prospectively, or to continue participating in the existing defined benefit plan. The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans was zero.

### Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2013 and 2012:

***Pension Benefits***

| **(in millions)** | **2013** | **2012** |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at January 1** | **$ 12,141** | **$ 10,993** |
| Actual return on plan assets | 673 | 1,488 |
| Company contributions | 323 | 282 |
| Benefits and expenses paid | (610) | (622) |
| **Fair value of plan assets at December 31** | **$ 12,527** | **$ 12,141** |
| | | |
| **Change in benefit obligation:** | | |
| **Projected benefit obligation at January 1** | **$ 15,541** | **$ 14,000** |
| Service cost for benefits earned | 468 | 396 |
| Interest cost | 627 | 658 |
| Actuarial (gain) loss | (1,950) | 1,099 |
| Plan amendments | - | 9 |
| Transitional costs | 1 | 1 |
| Benefits and expenses paid | (610) | (622) |
| **Projected benefit obligation at December 31 (1)** | **$ 14,077** | **$ 15,541** |
| | | |
| **Funded status:** | | |
| Current liability | $ (6) | $ (6) |
| Noncurrent liability | (1,544) | (3,394) |
| **Accrued benefit cost at December 31** | **$ (1,550)** | **$ (3,400)** |

(1) PG&E Corporation's accumulated benefit obligation was $12,659 million and $13,778 million at December 31, 2013 and 2012, respectively.

***Other Benefits***

| (in millions) | | 2013 | | 2012 |
|---|---|---|---|---|
| **Change in plan assets:** | | | | |
| **Fair value of plan assets at January 1** | **$** | **1,758** | **$** | **1,491** |
| Actual return on plan assets | | 64 | | 191 |
| Company contributions | | 145 | | 149 |
| Plan participant contribution | | 64 | | 55 |
| Benefits and expenses paid | | (139) | | (128) |
| **Fair value of plan assets at December 31** | **$** | **1,892** | **$** | **1,758** |
| | | | | |
| **Change in benefit obligation:** | | | | |
| **Benefit obligation at January 1** | **$** | **1,940** | **$** | **1,885** |
| Service cost for benefits earned | | 53 | | 49 |
| Interest cost | | 74 | | 83 |
| Actuarial gain | | (415) | | (23) |
| Plan amendments | | - | | 5 |
| Benefits paid | | (123) | | (119) |
| Federal subsidy on benefits paid | | 4 | | 5 |
| Plan participant contributions | | 64 | | 55 |
| **Benefit obligation at December 31** | **$** | **1,597** | **$** | **1,940** |
| | | | | |
| **Funded status [(1)] :** | | | | |
| Noncurrent asset | $ | 352 | $ | - |
| Noncurrent liability | | (57) | | (181) |
| **Accrued benefit cost at December 31** | **$** | **295** | **$** | **(181)** |

(1) At December 31, 2013, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position. At December 31, 2012, both the postretirement medical plan and the postretirement life insurance plan were in underfunded positions.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

***Pension Benefits***

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Service cost for benefits earned | $ 468 | $ 396 | $ 320 |
| Interest cost | 627 | 658 | 660 |
| Expected return on plan assets | (650) | (598) | (669) |
| Amortization of prior service cost | 20 | 20 | 34 |
| Amortization of net actuarial loss | 111 | 123 | 50 |
| **Net periodic benefit cost** | **576** | **599** | **395** |
| Less: transfer to regulatory account [1] | (238) | (301) | (139) |
| **Total** | **$ 338** | **$ 298** | **$ 256** |

[1] The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

***Other Benefits***

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Service cost for benefits earned | $ 53 | $ 49 | $ 42 |
| Interest cost | 74 | 83 | 91 |
| Expected return on plan assets | (79) | (77) | (82) |
| Amortization of transition obligation | - | 24 | 26 |
| Amortization of prior service cost | 23 | 25 | 27 |
| Amortization of net actuarial loss | 6 | 6 | 4 |
| **Net periodic benefit cost** | **$ 77** | **$ 110** | **$ 108** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record the net periodic benefit cost for pension benefits and other benefits as a component of accumulated other comprehensive income, net of tax. Net periodic benefit cost is composed of unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax.

Regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between pension expense or income calculated in accordance with GAAP for accounting purposes and pension expense or income for ratemaking, which is based on a funding approach. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income for the pension benefits related to the Utility's defined benefit pension plan. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability related to its other benefits and long term disability costs, for the excess of cumulative income for ratemaking over cumulative other benefits expense calculated in accordance with GAAP, and a portion of the credit balance in accumulated other comprehensive income. However, this recovery mechanism does not allow the Utility to record a regulatory asset for an underfunded position related to other benefits. Therefore, the charge remains in accumulated other comprehensive income (loss) for other benefits.

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2014 are as follows:

| ***Pension Benefit*** **(in millions)** | |
|---|---|
| Unrecognized prior service cost | $ 20 |
| Unrecognized net loss | 2 |
| **Total** | **$ 22** |

| ***Other Benefits*** **(in millions)** | |
|---|---|
| Unrecognized prior service cost | $ 23 |
| Unrecognized net loss | 2 |
| **Total** | **$ 25** |

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

**Valuation Assumptions**

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

| | **Pension Benefits** | | | **Other Benefits** | | |
|---|---|---|---|---|---|---|
| | **December 31,** | | | **December 31,** | | |
| | **2013** | **2012** | **2011** | **2013** | **2012** | **2011** |
| **Discount rate** | 4.89% | 3.98% | 4.66% | 4.70 - 5.00% | 3.75 - 4.08% | 4.41 - 4.77% |
| **Average rate of future compensation increases** | 4.00% | 4.00% | 5.00% | - | - | - |
| **Expected return on plan assets** | 6.50% | 5.40% | 5.50% | 3.50 - 6.70% | 2.90 - 6.10% | 4.40 - 5.50% |

The assumed health care cost trend rate as of December 31, 2013 was 8%, decreasing gradually to an ultimate trend rate in 2020 and beyond of approximately 5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| **(in millions)** | **One-Percentage-Point Increase** | **One-Percentage-Point Decrease** |
|---|---|---|
| Effect on postretirement benefit obligation | $ 86 | $ (88) |
| Effect on service and interest cost | 9 | (9) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.5% compares to a ten-year actual return of 8.7%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 494 Aa-grade non-callable bonds at December 31, 2013. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

**Investment Policies and Strategies**

The financial position of PG&E Corporation's and the Utility's funded employee benefit plans is driven by the relationship between plan assets and liabilities. As noted above, the funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs for financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trust's fixed-income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage this risk, PG&E Corporation's and the Utility's trusts hold significant allocations to fixed-income investments that include U.S. government securities, corporate securities, and other fixed-income securities. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. The equity investment allocation is implemented through portfolios that include common stock and commingled funds across multiple industry sectors. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Target allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening future funded status volatility. Derivative instruments such as equity index futures contracts are used to maintain existing equity exposure while adding exposure to fixed-income securities. In addition, derivative instruments such as equity index futures and fixed income futures are used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also used to hedge a portion of the currency of the global equity investments.

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | **Pension Benefits** | | | **Other Benefits** | | |
|---|---|---|---|---|---|---|
| | **2014** | **2013** | **2012** | **2014** | **2013** | **2012** |
| Global equity securities | 25% | 25% | 35% | 30% | 28% | 38% |
| Absolute return | 5% | 5% | 5% | 3% | 4% | 4% |
| Real assets | 10% | 10% | 10% | 8% | 8% | 8% |
| Extended fixed-income securities | 3% | 3% | 3% | -% | -% | -% |
| Fixed-income securities | 57% | 57% | 47% | 59% | 60% | 50% |
| **Total** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |

**Fair Value Measurements**

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2013 and 2012.

| | Fair Value Measurements | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | At December 31, | | | | | | | |
| | 2013 | | | | 2012 | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Benefits:** | | | | | | | | |
| Money market investments | $ 70 | $ - | $ - | **$ 70** | $ 112 | $ - | $ - | **$ 112** |
| Global equity securities | 1,123 | 2,363 | - | **3,486** | 402 | 3,017 | - | **3,419** |
| Absolute return | - | - | 554 | **554** | - | - | 513 | **513** |
| Real assets | 562 | - | 544 | **1,106** | 525 | - | 285 | **810** |
| Fixed-income securities: | | | | | | | | |
| U.S. government | 1,281 | 319 | - | **1,600** | 1,576 | 139 | - | **1,715** |
| Corporate | 1 | 4,230 | 625 | **4,856** | 3 | 4,275 | 611 | **4,889** |
| Other | 166 | 555 | - | **721** | - | 576 | - | **576** |
| **Total** | **$ 3,203** | **$ 7,467** | **$ 1,723** | **$ 12,393** | **$ 2,618** | **$ 8,007** | **$ 1,409** | **$ 12,034** |
| **Other Benefits:** | | | | | | | | |
| Money market investments | $ 31 | $ - | $ - | **$ 31** | $ 77 | $ - | $ - | **$ 77** |
| Global equity securities | 127 | 504 | - | **631** | 118 | 397 | - | **515** |
| Absolute return | - | - | 53 | **53** | - | - | 49 | **49** |
| Real assets | 67 | - | 38 | **105** | 68 | - | 28 | **96** |
| Fixed-income securities: | | | | | | | | |
| U.S. government | 119 | 5 | - | **124** | 148 | 5 | - | **153** |
| Corporate | 4 | 894 | 2 | **900** | 9 | 795 | 1 | **805** |
| Other | 14 | 37 | - | **51** | - | 38 | - | **38** |
| **Total** | **$ 362** | **$ 1,440** | **$ 93** | **$ 1,895** | **$ 420** | **$ 1,235** | **$ 78** | **$ 1,733** |
| **Total plan assets at fair value** | | | | **$ 14,288** | | | | **$ 13,767** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $131 million and $132 million at December 31, 2013 and 2012, respectively. These net assets and net liabilities were comprised primarily of cash, accounts receivable, accounts payable, and deferred taxes.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

***Money Market Investments***

Money market investments consist primarily of commingled funds of U.S. government short-term securities that are considered Level 1 assets and valued at the net asset value of $1 per unit. The number of units held by the plan fluctuates based on the unadjusted price changes in active markets for the funds' underlying assets.

***Equity Securities***

The global equity categories include equity investments in common stock and equity-index futures, and commingled funds comprised of equity across multiple industries and regions of the world. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets. Collateral posted related to these futures consist of money market investments that are considered Level 1 assets. Commingled funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled funds are categorized as Level 2 assets.

***Absolute Return***

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

***Real Assets***

The real asset category includes portfolios of commodities, commodities futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodities, commodities futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets. Collateral posted related to the commodities futures consist of money market investments that are considered Level 1 assets. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models, and valuation inputs that are unobservable and are considered Level 3 assets.

***Fixed-Income***

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments. Commingled funds are considered Level 2 assets. Corporate fixed-income also includes privately secured debt portfolios which are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on benchmark yields created using observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and index futures. Collateral posted related to the index futures consist of money market investments that are considered Level 1 assets. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

**Transfers Between Levels**

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No significant transfers between levels occurred in the years ended December 31, 2013 and 2012.

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2013 and 2012:

| | Pension Benefits | | | |
|---|---|---|---|---|
| **(in millions)** | **Absolute Return** | **Corporate Fixed-Income** | **Real Assets** | **Total** |
| Balance as of January 1, 2012 | $ 487 | $ 585 | $ 65 | **$ 1,137** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 26 | 28 | 12 | **66** |
| Relating to assets sold during the period | - | (1) | - | **(1)** |
| Purchases, issuances, sales, and settlements | | | | |
| Purchases | - | 12 | 208 | **220** |
| Settlements | - | (13) | - | **(13)** |
| **Balance as of December 31, 2012** | **$ 513** | **$ 611** | **$ 285** | **$ 1,409** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 37 | 1 | 49 | **87** |
| Relating to assets sold during the period | 4 | - | (3) | **1** |
| Purchases, issuances, sales, and settlements | | | | |
| Purchases | - | 20 | 352 | **372** |
| Settlements | - | (7) | **(139)** | **(146)** |
| **Balance as of December 31, 2013** | **$ 554** | **$ 625** | **$ 544** | **$ 1,723** |

| | Other Benefits | | | |
|---|---|---|---|---|
| **(in millions)** | **Absolute Return** | **Corporate Fixed-Income** | **Real Assets** | **Total** |
| Balance as of January 1, 2012 | $ 47 | $ 1 | 6 | **$ 54** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 2 | - | 1 | **3** |
| Relating to assets sold during the period | - | - | - | **-** |
| Purchases, issuances, sales, and settlements | | | | |
| Purchases | - | 1 | 21 | **22** |
| Settlements | - | (1) | - | **(1)** |
| **Balance as of December 31, 2012** | **$ 49** | **$ 1** | **$ 28** | **$ 78** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 4 | - | 3 | **7** |
| Relating to assets sold during the period | - | - | - | **-** |
| Purchases, issuances, sales, and settlements | | | | |
| Purchases | 12 | 1 | 21 | **34** |
| Settlements | (12) | - | (14) | **(26)** |
| **Balance as of December 31, 2013** | **$ 53** | **$ 2** | **$ 38** | **$ 93** |

There were no transfers out of Level 3 in 2013 and 2012.

## Cash Flow Information

### *Employer Contributions*

PG&E Corporation and the Utility contributed $323 million to the pension benefit plans and $145 million to the other benefit plans in 2013. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2013. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $71 million to the pension plan and other postretirement benefit plans, respectively, for 2014.

### *Benefits Payments and Receipts*

As of December 31, 2013, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

| **(in millions)** | **Pension** | **Other** | **Federal Subsidy** |
|---|---|---|---|
| 2014 | $ 613 | $ 90 | $ (6) |
| 2015 | 652 | 95 | (7) |
| 2016 | 692 | 100 | (8) |
| 2017 | 730 | 107 | (8) |
| 2018 | 766 | 113 | (9) |
| 2019 - 2023 | 4,326 | 609 | (35) |

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

## Defined Contribution Benefit Plans

PG&E Corporation sponsors employee retirement savings plans, including a defined contribution savings plan that is qualified as a 401(k) plan under the Internal Revenue Code 1986, as amended. These plans permit eligible employees to defer compensation, to make pre-tax and after-tax contributions, and provide for employer contributions to be made to eligible participants. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

| **(in millions)**<br>**Year ended December 31,** | |
|---|---|
| 2013 | $ 71 |
| 2012 | 67 |
| 2011 | 65 |

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

## NOTE 12: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the California Power Exchange wholesale electricity markets during this period.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. The Utility is uncertain when and how the remaining disputed claims will be resolved.

Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers through resolution of the remaining disputed claims, either through settlement or through the conclusion of the various FERC and judicial proceedings, are refunded to customers through rates in future periods.

The following table presents the changes in the remaining net disputed claims liability, which includes interest:

| **(in millions)** | | |
|---|---|---|
| Balance at December 31, 2012 | $ | 842 |
| Interest accrued, net of settlement | | 25 |
| Less: supplier settlements-principal amount | | (3) |
| **Balance at December 31, 2013** | **$** | **864** |

At December 31, 2013 and 2012, the remaining net disputed claims liability consisted of $154 million and $157 million, respectively, of remaining net disputed claims (classified on the Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) and $710 million and $685 million, respectively, of accrued interest (classified on the Consolidated Balance Sheets within interest payable).

At December 31, 2013 and 2012, the Utility held $291 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

Interest accrues on the remaining net disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates, these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims, the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims and when such interest is paid.

## NOTE 13: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

| (in millions) | Year Ended December 31, 2013 | 2012 | 2011 |
| --- | --- | --- | --- |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 7 | $ 7 | $ 6 |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 45 | $ 50 | $ 49 |
| Utility employee benefit due to PG&E Corporation | 57 | 51 | 33 |

At December 31, 2013 and 2012, the Utility had receivables of $22 million and $19 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $17 million, each year respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

## NOTE 14: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to natural gas matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. PG&E Corporation also has financial commitments described under "Other Commitments" below.

### Natural Gas Matters

On September 9, 2010, a natural gas transmission pipeline owned and operated by the Utility ruptured in San Bruno, California. The ensuing explosion and fire resulted in the deaths of eight people, numerous personal injuries, and extensive property damage. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been materially affected by the costs the Utility has incurred related to the ongoing regulatory proceedings, investigations, and civil lawsuits that commenced following the San Bruno accident.

#### *Pending CPUC Investigations*

There are three CPUC investigative enforcement proceedings pending against the Utility that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident.

The SED has issued investigative reports and briefs in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations. In July 2013, the SED recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows: (1) $300 million as a fine to the State General Fund, (2) $435 million for a portion of costs related to the Utility's PSEP that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future costs. (See "Disallowed Capital Costs" below.) Other parties, including the City of San Bruno, TURN, the CPUC's ORA, and the City and County of San Francisco, have recommended total penalties of at least $2.25 billion, including fines payable to the State General Fund of differing amounts.

The ALJs who oversee the investigations are expected to issue one or more presiding officers' decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued. Based on the CPUC's rules, the presiding officer's decisions would become the final decisions of the CPUC 30 days after issuance unless the Utility or another party filed an appeal with the CPUC, or a CPUC commissioner requested that the CPUC review the decision, within such time. If an appeal or review request is filed, other parties would have 15 days to provide comments but the CPUC could act before considering any comments.

At December 31, 2013, the Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including how the total number and duration of violations will be determined; how the various penalty recommendations made by the SED and other parties will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and how the CPUC will respond to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow PSEP costs that were previously authorized for recovery or other future costs. Disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance. See "Disallowed Capital Costs" below. Future disallowed expense and capital costs would be charged to net income in the period incurred.

***Other CPUC Enforcement Matters***

PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses that may be incurred in connection with the following matters.

*Gas Safety Citation Program.* The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of their natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility's operations or otherwise. The SED can exercise its discretion in determining whether to impose fines and the amount of such fines, or whether to take other enforcement action, based on the totality of the circumstances. The SED can consider such factors as the severity of the safety risk associated with each violation; the number and duration of the violations; whether the violation was self-reported, and whether corrective actions were taken. In January 2012, the SED imposed fines of $16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from $50,000 to $8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

*Natural Gas Transmission Pipeline Rights-of-Way.* In 2012, the Utility notified the CPUC and the SED that it is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments (such as building structures and vegetation overgrowth) from pipeline rights-of-way over a multi-year period. The SED could impose fines on the Utility or take other enforcement action in connection with this matter.

*Orders to Show Cause.* In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately $14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. The Utility recorded this amount as an expense for 2013. On January 23, 2014, the Utility filed an application for the rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable. Briefing on this OSC was completed on January 31, 2014.

***Disallowed Capital Costs***

In 2011, the CPUC ordered all natural gas operators in California to submit proposed plans to modernize and upgrade their natural gas transmission systems as well as associated cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP application that was filed in August 2011, but disallowed the Utility's request for rate recovery of a significant portion of costs the Utility forecasted it would incur through 2014. In October 2013, the Utility updated its PSEP application to present the results of its completed search and review of records relating to validation of operating pressure for all of the approximately 6,750 miles of the Utility's natural gas transmission pipelines. The Utility requested that the CPUC approve changes to the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects, and that the CPUC adjust authorized revenue requirements to reflect these changes. The Utility has requested that the CPUC issue a final decision by August 2014.

At December 31, 2013, the Utility has recorded cumulative charges of $549 million for PSEP capital costs that are expected to exceed the amount to be recovered. The Utility has requested that the CPUC authorize capital costs of $766 million under the PSEP, reflecting the proposed changes in the PSEP update application. Of this amount, approximately $280 million is recorded in Property, Plant, and Equipment on the Consolidated Balance Sheets at December 31, 2013. The Utility could record additional charges to the extent PSEP capital costs are higher than currently expected, or if additional capital costs are disallowed by the CPUC. The Utility's ability to recover PSEP capital costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

***Criminal Investigation***

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

***Third-Party Liability Claims***

The Utility has settled the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury and property damage, and other relief, including punitive damages, following the San Bruno accident. (Approximately 165 lawsuits on behalf of approximately 525 plaintiffs have been filed against the Utility.) At December 31, 2013, the Utility has recorded cumulative charges of $565 million as its best estimate of probable loss for third-party claims related to the San Bruno accident and has made cumulative payments of $520 million for settlements. In addition, the Utility has incurred cumulative expenses of $86 million for associated legal costs. The Utility's liability for third-party claims is included in other current liabilities in the Consolidated Balance Sheets and totaled $45 million at December 31, 2013 and $146 million at December 31, 2012.

The aggregate amount of insurance coverage for third-party liability attributable to the San Bruno accident is approximately $992 million in excess of a $10 million deductible. Through December 31, 2013, the Utility has recognized cumulative insurance recoveries of $354 million for third-party claims and associated legal costs. These amounts were recorded as a reduction to operating and maintenance expense in the Consolidated Statements of Income. Although the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal costs) relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

***Class Action Complaint***

On August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages.

PG&E Corporation and the Utility contest the plaintiffs' allegations. On May 23, 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter if the lower court's ruling is reversed.

**Other Legal and Regulatory Contingencies**

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred.

Accruals for other legal and regulatory contingencies (excluding amounts related to natural gas matters above) totaled $43 million at December 31, 2013 and $34 million at December 31, 2012. These amounts are included in other current liabilities in the Consolidated Balance Sheets. The estimated reasonably possible range of loss for these matters in excess of the recorded accrual is not material. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Environmental Remediation Contingencies**

The Utility is required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The following table presents the changes in the environmental remediation liability:

| **(in millions)** | |
|---|---|
| Balance at December 31, 2012 | $ 910 |
| Additional remediation costs accrued: | |
| Transfer to regulatory account for recovery | 116 |
| Amounts not recoverable from customers | 49 |
| Less: Payments | (175) |
| **Balance at December 31, 2013** | **$ 900** |

The environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

| | **Balance at December 31,** | |
|---|---|---|
| **(in millions)** | **2013** | **2012** |
| Utility-owned natural gas compressor site near Hinkley, California [1] | $ 190 | $ 226 |
| Utility-owned natural gas compressor site near Topock, Arizona [1] | 264 | 239 |
| Utility-owned generation facilities (other than for fossil fuel-fired), other facilities, and third-party disposal sites | 160 | 158 |
| Former MGP sites owned by the Utility or third parties | 184 | 181 |
| Fossil fuel-fired generation facilities and sites | 102 | 106 |
| **Total environmental remediation liability** | **$ 900** | **$ 910** |

[1] See "Natural Gas Compressor Sites" below.

At December 31, 2013, the Utility expected to recover $579 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

***Natural Gas Compressor Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor sites near Hinkley, California and Topock, Arizona. The Utility is also required to take measures to abate the effects of the contamination on the environment.

***Hinkley Site***

The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. On July 17, 2013, the Regional Board certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue the final project permits and a final clean-up order in phases through 2014 and into 2015. As the permits and order are issued, the Utility will obtain additional clarity on the total costs associated with the final remedy and related activities. In January 2014, the Regional Board also approved an updated background study plan prepared in consultation with the U.S. Geological Survey, the results of which will define the final cleanup standards. The background study is not expected to be complete until 2018.

The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, monitor and control movement of the plume, and provided replacement water to affected residents. As of December 31, 2013, approximately 380 residential households located near the plume boundary were covered by the Utility's whole house water replacement program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to maintain and operate the program for five years or until the State of California has adopted a drinking water standard specifically for hexavalent chromium at which time the program will be evaluated. The State of California recently proposed draft regulations for hexavalent chromium and is expected to issue a final standard by June 2014.

The Utility's environmental remediation liability at December 31, 2013 reflects the Utility's best estimate of probable future costs associated with its final remediation plan, interim remediation measures, and whole house water program. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, the extent of the chromium plume boundary, and adoption of a final drinking water standard by the State of California. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

***Topock Site***

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. The California Department of Toxic Substances Control has approved the Utility's final remediation plan to contain and remediate the underground plume of hexavalent chromium, under which the Utility will implement an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility expects to submit its final remedial design plan in 2014 for approval to begin construction of the groundwater treatment system. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River.

The Utility's environmental remediation liability at December 31, 2013 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

### *Reasonably Possible Environmental Contingencies*

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.7 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations during the period in which they are recorded.

### Nuclear Insurance

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $13.6 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $13.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a maximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident. In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the liability insurance.

**Commitments**

***Third-Party Power Purchase Agreements***

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery. The costs incurred for all power purchases and electric capacity were as follows:

| (in millions) | 2013 | 2012 | 2011 |
|---|---|---|---|
| Qualifying facilities [1] | $ 813 | $ 779 | $ 1,069 |
| Renewable energy contracts | 1,281 | 815 | 622 |
| Other power purchase agreements | 902 | 661 | 690 |

[1] Costs incurred include $ 271 , $286, and $297 attributable to renewable energy contracts with qualifying facilities at December 31, 2013 , 2012 , and 2011 , respectively.

*Qualifying Facility Power Purchase Agreement* – The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. As of December 31, 2013, the Utility had agreements with 170 QFs that are in operation, which expire at various dates between 2014 and 2028.

*Renewable Energy Power Purchase Agreements* – The Utility is required to gradually increase the amount of renewable energy that it delivers to its customers in order to comply with California's renewable portfolio standard requirement. The Utility has entered into various contracts to purchase renewable energy to help meet the renewable portfolio standard requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities. The Utility's commitments for energy payments under these renewable energy agreements are expected to grow significantly.

*Other Power Purchase Agreements* – The Utility has entered into several power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. The Utility also has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

At December 31, 2013, the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones were as follows:

| (in millions) | Qualifying Facility | Renewable (Other than QFs) | Other | Total Payments |
|---|---|---|---|---|
| 2014 | $ 913 | $ 1,906 | $ 829 | $ 3,648 |
| 2015 | 707 | 2,102 | 770 | 3,579 |
| 2016 | 587 | 2,109 | 722 | 3,418 |
| 2017 | 450 | 2,104 | 684 | 3,238 |
| 2018 | 406 | 1,962 | 640 | 3,008 |
| Thereafter | 1,614 | 30,242 | 2,984 | 34,840 |
| **Total** | **$ 4,677** | **$ 40,425** | **$ 6,629** | **$ 51,731** |

The following table shows the future fixed capacity payments due under QF agreements that are treated as capital leases. (These amounts are also included in the table above.) These payments are discounted to their present value in the table below using the Utility's incremental borrowing rate at the inception of the leases. These capital lease QF agreements expire between April 2014 and September 2021. The amount of this discount is shown in the table below as the amount representing interest.

| **(in millions)** | | |
|---|---|---|
| 2014 | $ | 27 |
| 2015 | | 24 |
| 2016 | | 22 |
| 2017 | | 18 |
| 2018 | | 12 |
| Thereafter | | 8 |
| **Total fixed capacity payments** | | **111** |
| Less: amount representing interest | | 14 |
| **Present value of fixed capacity payments** | **$** | **97** |

Minimum lease payments associated with the lease obligations are included in the Utility's cost of electricity. The timing of the recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity.

The present value of the fixed capacity payments due under these agreements is recorded on the Consolidated Balance Sheets. At December 31, 2013 and 2012, current liabilities – other included $23 million and $29 million, respectively, and noncurrent liabilities – other included $74 million and $96 million, respectively. The corresponding assets at December 31, 2013 and 2012 of $97 million and $125 million including accumulated amortization of $176 million and $148 million, respectively are included in property, plant, and equipment on the Consolidated Balance Sheets.

***Natural Gas Supply, Transportation, and Storage Commitments***

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

At December 31, 2013, the Utility's undiscounted future expected payment obligations for natural gas supplies, transportation and storage were as follows:

| (in millions) | | |
| --- | --- | --- |
| 2014 | $ | 727 |
| 2015 | | 198 |
| 2016 | | 150 |
| 2017 | | 108 |
| 2018 | | 108 |
| Thereafter | | 756 |
| **Total** | **$** | **2,047** |

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts less than 1 year, amounted to $1.6 billion in 2013, $1.3 billion in 2012, and $1.8 billion in 2011.

***Nuclear Fuel Agreements***

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have remaining terms ranging from one to 12 years and are intended to ensure long-term nuclear fuel supply. The contracts for uranium and for conversion and enrichment services provide for 100% coverage of reactor requirements through 2020, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2017. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

At December 31, 2013, the undiscounted future expected payment obligations for nuclear fuel were as follows:

| (in millions) | | |
| --- | --- | --- |
| 2014 | $ | 145 |
| 2015 | | 162 |
| 2016 | | 146 |
| 2017 | | 148 |
| 2018 | | 132 |
| Thereafter | | 647 |
| **Total** | **$** | **1,380** |

Payments for nuclear fuel amounted to $162 million in 2013, $118 million in 2012, and $77 million in 2011.

***Other Commitments***

PG&E Corporation and the Utility have other commitments relating to operating leases. At December 31, 2013, the future minimum payments related to these commitments were as follows:

| (in millions) | | |
| --- | --- | --- |
| 2014 | $ | 42 |
| 2015 | | 37 |
| 2016 | | 34 |
| 2017 | | 27 |
| 2018 | | 24 |
| Thereafter | | 193 |
| **Total** | **$** | **357** |

Payments for other commitments relating to operating leases amounted to $40 million in 2013, $32 million in 2012, and $27 million in 2011. PG&E Corporation and the Utility had operating leases on office facilities expiring at various dates from 2014 to 2023. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2% to 5%. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension options ranging between one and five years.

**QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)**

| | Quarter ended | | | |
|---|---|---|---|---|
| **(in millions, except per share amounts)** | **December 31** | **September 30** | **June 30** | **March 31** |
| **2013** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 3,975 | $ 4,175 | $ 3,776 | $ 3,672 |
| Operating income | 333 | 291 | 636 | 502 |
| Income tax (benefit) provision | 25 | (24) | 153 | 114 |
| Net income | 90 | 164 | 332 | 242 |
| Income available for common shareholders | 86 | 161 | 328 | 239 |
| Comprehensive income | 210 | 165 | 352 | 252 |
| Net earnings per common share, basic | 0.19 | 0.36 | 0.74 | 0.55 |
| Net earnings per common share, diluted | 0.19 | 0.36 | 0.74 | 0.55 |
| Common stock price per share: | | | | |
| High | 42.75 | 46.37 | 48.44 | 44.53 |
| Low | 40.07 | 40.76 | 43.59 | 40.47 |
| **UTILITY** | | | | |
| Operating revenues | $ 3,973 | $ 4,174 | $ 3,775 | $ 3,671 |
| Operating income | 360 | 292 | 635 | 503 |
| Income tax (benefit) provision | 65 | (20) | 160 | 121 |
| Net income | 138 | 162 | 329 | 237 |
| Income available for common stock | 134 | 159 | 325 | 234 |
| Comprehensive income | 231 | 166 | 333 | 242 |
| | | | | |
| **2012** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 3,830 | $ 3,976 | $ 3,593 | $ 3,641 |
| Operating income | 125 | 614 | 467 | 487 |
| Income tax (benefit) provision | (54) | 100 | 87 | 104 |
| Net income (loss) | (9) | 364 | 239 | 236 |
| Income (loss) available for common shareholders | (13) | 361 | 235 | 233 |
| Comprehensive income | 77 | 372 | 247 | 246 |
| Net earnings (loss) per common share, basic | (0.03) | 0.84 | 0.56 | 0.56 |
| Net earnings (loss) per common share, diluted | (0.03) | 0.84 | 0.55 | 0.56 |
| Common stock price per share: | | | | |
| High | 43.48 | 46.51 | 45.20 | 43.72 |
| Low | 39.71 | 42.41 | 42.04 | 40.16 |
| **UTILITY** | | | | |
| Operating revenues | $ 3,829 | $ 3,974 | $ 3,592 | $ 3,640 |
| Operating income | 127 | 613 | 467 | 488 |
| Net income | 13 | 340 | 227 | 231 |
| Income tax provision | (30) | 122 | 93 | 113 |
| Income available for common stock | 9 | 337 | 223 | 228 |
| Comprehensive income | 96 | 348 | 235 | 241 |

The Utility recorded a charge to net income of $196 million in the third quarter of 2013 and $353 million during the fourth quarter 2012, for disallowed capital expenditures associated with the Utility's pipeline safety enhancement plan. See Note 14 of the Notes to the Consolidated Financial Statements.

The Utility recorded a provision of $110 million and $80 million in the third quarter 2013 and in the second quarter 2012, respectively, for estimated third-party claims related to the San Bruno accident. During the second quarter 2013 and third quarter 2013, the Utility recognized $45 million and $25 million, respectively, for insurance claims. During the first quarter 2012, second quarter of 2012, third quarter of 2012, and fourth quarter 2012 the Utility recognized $11 million, $25 million, $99 million, and $50 million, respectively, for insurance recoveries. See Note 14 of the Notes to the Consolidated Financial Statements.

**MANAGEM ENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of PG&E Corporation and Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2013.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2013 and 2012, and the Company's related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 to the consolidated financial statements, there are three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2014 expressed an unqualified opinion on the Company's and the Utility's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 11, 2014

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and the Utility and our report dated February 11, 2014 expressed an unqualified opinion on those financial statements and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 11, 2014

**Significant Subsidiaries**

| Parent of Significant Subsidiary | Name of Significant Subsidiary | Jurisdiction of Formation of Subsidiary | Names under which Significant Subsidiary does business |
|---|---|---|---|
| PG&E Corporation | Pacific Gas and Electric Company | CA | Pacific Gas and Electric Company<br>PG&E |
| Pacific Gas and Electric Company | None | | |

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-172393 on Form S-3, 333-144498 on Form S-3D, and 333-73054, 333-129422 and 333-176090 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488 and 333-172394 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 11, 2014, relating to the consolidated financial statements of PG&E Corporation and subsidiaries ("the Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") (which report expresses an unqualified opinion and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties), the consolidated financial statement schedules of the Company and the Utility, and the effectiveness of the Company's and the Utility's internal control over financial reporting, appearing in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2013.

/s/ DELOITTE & TOUCHE LLP

February 11, 2014
San Francisco, California

**POWER OF ATTORNEY**

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2013 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 7th day of February, 2014.

| | |
|---|---|
| /s/ LEWIS CHEW<br>Lewis Chew | /s/ ROGER H. KIMMEL<br>Roger H. Kimmel |
| /s/ C. LEE COX<br>C. Lee Cox | /s/ RICHARD A. MESERVE<br>Richard A. Meserve |
| /s/ ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | /s/ FORREST E. MILLER<br>Forrest E. Miller |
| /s/ FRED J. FOWLER<br>Fred J. Fowler | /s/ ROSENDO G. PARRA<br>Rosendo G. Parra |
| /s/ MARYELLEN C. HERRINGER<br>Maryellen C. Herringer | /s/ BARBARA L. RAMBO<br>Barbara L. Rambo |
| Richard C. Kelly | /s/ BARRY LAWSON WILLIAMS<br>Barry Lawson Williams |

**POWER OF ATTORNEY**

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2013 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 7th day of February, 2014.

/s/ LEWIS CHEW
Lewis Chew

/s/ C. LEE COX
C. Lee Cox

/s/ ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.

/s/ FRED J. FOWLER
Fred J. Fowler

/s/ MARYELLEN C. HERRINGER
Maryellen C. Herringer

/s/ CHRISTOPHER P. JOHNS
Christopher P. Johns

Richard C. Kelly

/s/ ROGER H. KIMMEL
Roger H. Kimmel

/s/ RICHARD A. MESERVE
Richard A. Meserve

/s/ FORREST E. MILLER
Forrest E. Miller

/s/ ROSENDO G. PARRA
Rosendo G. Parra

/s/ BARBARA L. RAMBO
Barbara L. Rambo

/s/ BARRY LAWSON WILLIAMS
Barry Lawson Williams

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.
Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Kent M. Harvey, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

KENT M. HARVEY
Kent M. Harvey
Senior Vice President and Chief Financial Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

CHRISTOPHER P. JOHNS
Christopher P. Johns
President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Dinyar B. Mistry, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

DINYAR B. MISTRY
Dinyar B. Mistry
Vice President, Chief Financial Officer, and Controller

Exhibit 32.1

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2013 ("Form 10-K"), I, Anthony F. Earley, Jr., Chairman, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ANTHONY F. EARLEY, JR.

ANTHONY F. EARLEY, JR.
Chairman, Chief Executive Officer and President

February 11, 2014

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2013 ("Form 10-K"), I, Kent M. Harvey, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

KENT. M. HARVEY
KENT M. HARVEY
Senior Vice President and
Chief Financial Officer

February 11, 2014

Exhibit 32.2

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2013 (“Form 10-K”), I, Christopher P. Johns, President of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

CHRISTOPHER P. JOHNS
CHRISTOPHER P. JOHNS
President

February 11, 2014

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the quarter ended September 30, 2013 (“Form 10-K”), I, Dinyar B. Mistry, Vice President, Chief Financial Officer, and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

DINYAR B. MISTRY

DINYAR B. MISTRY
Vice President, Chief Financial Officer, and Controller

February 11, 2014

# Exhibit 3

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-K**

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2014

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _________ to ___________

| Commission File Number | Exact Name of Registrant as Specified In Its Charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company®
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each class | Name of each exchange on which registered |
|---|---|
| **PG&E Corporation:** Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company:** First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE Amex Equities |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2014, the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $22,602 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |

**Common Stock outstanding as of January 27, 2015:**

| | |
|---|---|
| PG&E Corporation: | 476,399,910 shares |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

| | |
|---|---|
| Designated portions of the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |

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**UNITS OF MEASUREMENT**

| | | |
|---|---|---|
| 1 Kilowatt (kW) | = | One thousand watts |
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt (GW) | = | One million kilowatts |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |
| 1 Bcf | = | One billion cubic feet |
| 1 MDth | = | One thousand decatherms |

## GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2014 Annual Report | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2014, including the information incorporated by reference into the report |
| AB | Assembly Bill |
| AFUDC | allowance for funds used during construction |
| ALJ | administrative law judge |
| ARO | asset retirement obligation |
| CAISO | California Independent System Operator |
| CARB | California Air Resources Board |
| CCA | Community Choice Aggregator |
| Central Coast Board | Central Coast Regional Water Quality Control Board |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DOE | Department of Energy |
| EPA | Environmental Protection Agency |
| EPS | earnings per common share |
| EV | electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| IRS | Internal Revenue Service |
| LTIP | long term incentive plan |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations |
| NEIL | Nuclear Electric Insurance Limited |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| ORA | Office of Ratepayer Advocates |
| PSEP | pipeline safety enhancement plan |
| QF | Qualifying facility |
| Regional Board | California Regional Water Quality Control Board, Lahontan Region |
| REITS | Global real estate investment trust |
| ROE | return on equity |
| RPS | renewable portfolio standard |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |
| Water Board | California State Water Resources Control Board |

## PART I

## ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is subject to the jurisdiction of the FERC and the NRC. PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found in Item 6. Selected Financial Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

At December 31, 2014, PG&E Corporation and its subsidiaries had 22,581 employees, including 22,569 employees of the Utility. Of the Utility's regular employees, 13,649 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW"); the Engineers and Scientists of California ("ESC"); and the Service Employees International Union ("SEIU"). The two agreements with IBEW, and the single agreement with ESC, will expire on December 31, 2015. The SEIU collective bargaining agreement will expire on July 31, 2015.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, *www.pgecorp.com*, and the Utility's website, *www.pge.com*, as promptly as practicable after they are filed with, or furnished to, the SEC. The information contained on these websites is not part of this or any other report that PG&E Corporation and the Utility files with, or furnishes to, the SEC.

This Annual Report on Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see "Item 1A. Risk Factors" and the section entitled "Cautionary Language Regarding Forward-Looking Statements" in Item 7. MD&A. In particular, PG&E Corporation's and the Utility's financial results are expected to be materially affected by the final outcome of the CPUC's pending investigative enforcement proceedings against the Utility. These investigations relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the pipeline accident that occurred in San Bruno, California on September 9, 2010. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been materially affected by the costs the Utility has incurred related to shareholder funded safety work, the ongoing regulatory investigations, and civil lawsuits that commenced following the San Bruno accident. In addition, PG&E Corporation's and the Utility's financial results could be materially affected by the outcome of the federal criminal prosecution of the Utility and the other enforcement matters discussed in "Enforcement and Litigation Matters" in Item 7. MD&A.

### Regulatory Environment

The Utility's business is subject to a complex set of energy, environmental and other laws, regulations, and regulatory proceedings at the federal, state, and local levels. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. See "Enforcement and Litigation Matters" and "Ratemaking and Other Regulatory Proceedings" in Item 7. MD&A for discussion of specific pending regulatory matters that are expected to materially affect PG&E Corporation and the Utility.

PG&E Corporation is a "public utility holding company" as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

*The California Public Utilities Commission*

The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electricity generation, and natural gas transmission and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The California Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to increasing renewable energy resources, the development and widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, and the development of energy storage technologies and facilities. In addition, the CPUC is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs.

The CPUC enforces state laws that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility electric and gas facilities. The CPUC also has authority to enforce compliance with certain federal regulations related to the safety of natural gas facilities. The CPUC has adopted a gas safety enforcement program and authorized the SED to issue citations and impose fines for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. (See "Enforcement and Litigation Matters" in Item 7. MD&A for information about the presiding officer decisions issued in the three CPUC investigative enforcement proceedings pending against the Utility and SED's enforcement actions taken against the Utility.) In December 2014, the CPUC also adopted an interim electric safety enforcement program that became effective January 1, 2015. (On January 7, 2015, the Utility requested that the CPUC reconsider this decision.) Under both the gas and electric programs, the SED can impose fines up to $50,000 per violation, per day. The CPUC is expected to review both safety programs during 2015 to determine whether any further changes are needed.

In addition, the CPUC conducts audits and reviews of the Utility's accounting, performance and compliance with regulatory guidelines, as well as investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies. The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation's Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see "Liquidity and Financial Resources" in Item 7. MD&A and Item 1A. Risk Factors.)

*The Federal Energy Regulatory Commission and the California Independent System Operator*

The FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates interconnections of transmission systems with other electric systems and generation facilities, tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation's electricity transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. The FERC has authority to impose fines of up to $1 million per day for violation of certain federal statutes and regulations.

The CAISO is the FERC-approved regional transmission organization for the Utility's service territory. The CAISO controls the operation of the transmission system in California and provides open access transmission service on a nondiscriminatory basis. The CAISO also is responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generation capacity, and ensuring that the reliability of the transmission system is maintained.

*The Nuclear Regulatory Commission*

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electric Generation Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future.

### *Other Regulation*

The California Energy Resources Conservation and Development Commission, commonly called the CEC, is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

The CARB is the state agency charged with setting and monitoring GHG and other emission limits. The CARB also is responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California to 1990 levels by 2020. (See "Environmental Regulation — Air Quality and Climate Change" below.)

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date.

## Ratemaking Mechanisms

The Utility's rates for electricity and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service including a return on invested capital ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct various proceedings to determine the annual amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (maintenance, administration and general expenses) and capital costs (depreciation, tax, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that it is allowed to "pass-through" to customers, including its costs to procure electricity, natural gas and nuclear fuel, to administer public purpose and customer programs, and to decommission its nuclear facilities.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. The authorized rate of return on all other assets is set in the CPUC's cost of capital proceeding. Other than its electric transmission and certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume. Regulatory balancing accounts, or revenue adjustment mechanisms, ensure that the Utility will fully collect its authorized base revenue requirements. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impact Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

To develop retail rates, authorized revenue requirements are allocated among customer classes which are mainly residential, commercial, industrial, and agricultural. Rate changes become effective prospectively on or after the date of CPUC or FERC decisions.

California AB 327, which became effective on January 1, 2014, repealed prior law that restricted the CPUC's ability to change residential electric rates and to reduce the level of rate assistance for certain low-income customers. AB 327 also authorized the CPUC to approve fixed charges to be collected from residential customers. In 2012, the CPUC opened a rulemaking proceeding to examine residential rate design in California that, consistent with AB 327, allows the CPUC to simplify the rate structure to bring marginal rates closer to reflecting the Utility's actual costs. In February 2014, as ordered by the CPUC, the Utility submitted a long-term residential rate reform plan that proposes a fixed customer charge, gradual flattening of the tiered rate structure, and an optional time-of-use rate. The CPUC is expected to issue a final decision by the summer of 2015.

AB 327 also requires the CPUC to develop a new structure for net energy metering by December 31, 2015, that must be implemented no later than July 1, 2017. California's net energy metering program currently allows customers installing renewable distributed generation to receive bill credits for power delivered to the grid at their full retail rate. Increasing levels of self-generation of electricity by customers, coupled with net metering and retail rates that do not reflect the Utility's cost structure, has shifted costs to the remaining customers. AB 327 gives the CPUC new authority to reduce the cost shift associated with renewable distributed generation through residential rate and net energy metering reform. In July 2014, the CPUC began a rulemaking proceeding to develop a successor to the existing net energy metering program to comply with the requirements of AB 327. The CPUC is expected to issue a proposed decision in the fall of 2015.

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs. (See "Results of Operations" in Item 7. MD&A.)

***Base Revenues***

*General Rate Cases*

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs, including return on rate base, related to its electricity and natural gas distribution and Utility owned electricity generation operations. The CPUC generally conducts a GRC every three years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases (known as "attrition adjustments") in revenue requirements for the subsequent years of the GRC period. Attrition rate adjustments are generally provided for cost increases related to inflation and increases in invested capital. Parties in the Utility's GRC include the ORA and TURN, who generally represent the overall interests of residential customers, as well as a myriad of other intervenors who represent residential and other customer interests.

On August 14, 2014, the CPUC issued a decision in the Utility's 2014 GRC, authorizing the Utility to collect a total 2014 revenue requirement of approximately $7.1 billion to recover anticipated costs associated with electric generation, as well as electric and natural gas distribution (See "Results of Operations" in Item 7. MD&A.) The CPUC also authorized attrition increases of $324 million for 2015 and $371 million for 2016.

On December 9, 2014, the CPUC issued a decision adopting a risk-based decision-making framework for the CPUC to use in evaluating future major rate cases. The CPUC ordered the utilities to file an application on May 1, 2015, to initiate a new proceeding called the Safety Model Assessment Proceeding in which the CPUC will review the models the utilities use to assess and prioritize risks. After this proceeding concludes, each utility would file an application to initiate the first phase of their next GRC. In this phase, known as the Risk Assessment Mitigation Phase, the CPUC will examine the utility's assessment of its key risks and its proposed programs for mitigating those risks.

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in the GT&S rate case. In December 2013, the Utility filed its 2015 GT&S rate case application (covering 2015 through 2017) requesting the CPUC approve a total annual revenue requirement of $1.29 billion for anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2015. See "Ratemaking and Other Regulatory Proceedings – 2015 GT&S Rate Case" in Item 7. MD&A for additional information.

*Cost of Capital Proceedings*

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2016, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also authorized the Utility to earn a 10.40% ROE effective January 1, 2013, compared to the 11.35% previously authorized. The Utility's ROE can be automatically adjusted if the utility bond index changes by certain thresholds on an annual basis. The index changes to date have not exceeded the threshold so the 2015 ROE has remained at 10.40%. The Utility's next cost of capital application is due in April 2016.

*Electricity Transmission Owner Rate Cases*

The FERC determines the amount of authorized revenue requirement, including rate of return on electric transmission assets, that the Utility may collect in rates in the TO tariff rate case. The Utility generally files a TO tariff rate case every year. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and are collected from retail electric customers. (See "Ratemaking and Other Regulatory Proceedings – FERC Transmission Owner Rate Cases" in Item 7. MD&A.) The Utility also recovers revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in 1998. These wholesale customers are charged individualized rates based on the terms of their contracts.

***Revenues to Recover Energy Procurement and Other Pass-Through Costs***

*Electricity Procurement Costs*

California investor-owned electric utilities are responsible for procuring electricity required to meet customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electricity contracts. The utilities are responsible for scheduling and bidding electric generation resources, including electricity procured from third parties or the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their procurement plans based on long-term demand forecasts. In January 2012, the CPUC approved the Utility's procurement plan (covering 2012 through 2020).

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved electricity procurement plans without further after-the-fact reasonableness review. Costs associated with electricity purchases may be disallowed if they are not in compliance with the CPUC-approved plan or if the utility failed to follow the principles of least-cost dispatch. The Utility recovers its electricity procurement costs annually through the energy resource recovery account ("ERRA"). (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.) Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG costs, and generation fuel expense and approves a forecasted revenue requirement. The CPUC may adjust a utility's retail electricity rates more frequently if the forecasted aggregate over-collections or under-collections in the ERRA exceed five percent of its prior year electricity procurement revenues. The CPUC performs an annual compliance review of the transactions recorded in the ERRA.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, the renewable energy mandate, and resource adequacy requirements. See "Electric Utility Operations – Electricity Resources" below as well as Note 14 of the Notes to the Consolidated Financial Statements in Item 8 for additional information.

*Natural Gas Procurement and Transportation Costs*

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as "core" customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments through its retail gas rates subject to limits as set forth in its Core Procurement Incentive Mechanism ("CPIM"). The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates. This is accomplished through monthly advice letters that are effective upon filing. The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electricity rates.

The CPIM protects the Utility against after-the-fact reasonableness reviews of these gas procurement costs. Under the CPIM, the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by FERC-approved tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, and the applicable Canadian tariffs are approved by the Alberta Utilities Commission and the National Energy Board. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as a cost of electricity.

*Costs Associated with Public Purpose and Customer Programs*

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide a discount rate for low-income customers, known as California Alternate Rates for Energy ("CARE"), which is subsidized by the Utility's other customers.

*Nuclear Decommissioning Costs*

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover the estimated costs through rates. Nuclear decommissioning charges collected through rates are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit.

**Electric Utility Operations**

The Utility generates electricity and provides electricity transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides "bundled" services (i.e., electricity, transmission and distribution services) to most customers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations.

During 2014, the Utility continued to make improvements to its electric transmission and distribution systems to accommodate the integration of new renewable energy resources, distributed generation resources, and energy storage facilities, and to help create a platform for the development of new Smart Grid technologies. The Utility plans to continue making similar improvements in 2015. In December 2014, the CPUC issued a decision that permits the California investor-owned electric utilities to own EV retail charging equipment in their respective service territories to help meet the state's goal of reducing GHG emissions by promoting cleaner transportation. On February 9, 2015, the Utility filed an application to request that the CPUC approve the Utility's proposal to develop, maintain, and operate an EV-charging infrastructure in its service territory. (For more information about the Utility's application, see "Ratemaking And Other Regulatory Proceedings" in Item 7. MD&A.)

***Electricity Resources***

The Utility is required to maintain physical generating capacity adequate to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule all of the electricity resources within its portfolio in the most cost-effective way**.**

The following table shows the percentage of the Utility's total deliveries of electricity to customers in 2014 represented by each major electricity resource, and further discussed below.

Total 2014 Actual Electricity Generated and Procured – 74,547 GWh [(1)]:

| | Percent of Bundled Retail Sales | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 20.6 % | |
| Small Hydroelectric | 0.8 % | |
| Large Hydroelectric | 6.6 % | |
| Fossil fuel-fired | 7.4 % | |
| Solar | 0.4 % | |
| Total | | 35.8 % |
| | | |
| Qualifying Facilities | | |
| Renewable | 3.7 % | |
| Non-Renewable | 8.5 % | |
| Total | | 12.2 % |
| Irrigation Districts and Water Agencies | | |
| Small Hydroelectric | 0.1 % | |
| Large Hydroelectric | 0.8 % | |
| Total | | 0.9 % |
| Other Third-Party Purchase Agreements | | |
| Renewable | 22.0 % | |
| Large Hydroelectric | 0.9 % | |
| Non-Renewable | 6.6 % | |
| Total | | 29.5 % |
| Others, Net [(2)] | | 21.6 % |
| **Total [(3)]** | | **100.0 %** |

[(1)] This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
[(2)] Mainly comprised of net CAISO open market purchases.
[(3)] Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by transmission and distribution related system losses.

*Renewable Energy Resources*. California law requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers to at least 33% of their total annual retail sales. This program, known as the RPS program, became effective in December 2011, established three multi-year compliance periods that have gradually increasing RPS targets: 2011 through 2013, 2014 through 2016, and 2017 through 2020. After 2020, the RPS compliance periods will be annual.

Renewable generation resources, for purposes of the RPS program, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. During 2014, 27% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 22% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (3.8%), the Utility's small hydroelectric facilities (0.8%), and the Utility's solar facilities (0.5%).

The total 2014 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales |
|---|---|---|
| Biopower | 3,458 | 4.6% |
| Geothermal | 3,867 | 5.2% |
| Wind | 5,399 | 7.2% |
| RPS-Eligible Hydroelectric | 981 | 1.3% |
| Solar | 6,478 | 8.7% |
| **Total** | **20,183** | **27.0%** |

*Energy Storage.* As required by California law, the CPUC has established initial energy storage procurement targets to be achieved by each load-serving entity, such as the Utility. The Utility has an 80.5 MW of energy storage target to meet its 2014 energy storage plan. In December 2014, the Utility held its first competitive request for two types of proposals: (1) an energy storage agreement with the owner of an energy storage facility that would enable the Utility to offer stored energy into the CAISO market and (2) a purchase and sale agreement under which the counterparty would build a storage facility and transfer the facility to the Utility provided the facility meets certain operational conditions. Offers are due by February 17, 2015. The Utility intends to complete negotiations and execute contracts by October 1, 2015 and to submit the executed contracts for CPUC approval by December 1, 2015.

*Owned Generation Facilities.* At December 31, 2014, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---|---|---|---|
| Nuclear [1]: | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric [2]: | | | |
| Conventional | 16 counties in northern and central California | 104 | 2,677 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| Fuel Cell: | | | |
| CSU East Bay Fuel Cell | Alameda | 1 | 1 |
| SF State Fuel Cell | San Francisco | 2 | 2 |
| Photovoltaic [3]: | Various | 13 | 152 |
| **Total** | | **137** | **7,684** |

[1] The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the year ended December 31, 2014, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 87%. The ability of the Utility to produce nuclear generation depends on the availability of nuclear fuel. The Utility has entered into various purchase agreements for nuclear fuel that are intended to ensure long-term fuel supply. (See Note 14 to the Consolidated Financial Statements in Item 8.) The Diablo Canyon power plant refueling outages are typically scheduled every 20 months. The average length of a refueling outage over the last five years has been approximately 49.5 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors. The NRC operating licenses for the two operating units at Diablo Canyon include various license conditions related to seismic design and safety. The current licenses expire in 2024 and 2025. In November 2009, the Utility filed an application with the NRC to seek the renewal of the licenses, a process which can take several years. After the March 2011 earthquake in Japan that damaged nuclear facilities, the NRC granted the Utility's request to delay processing its renewal application until certain advanced seismic studies of the fault zones in the region surrounding Diablo Canyon were completed. The seismic studies have been completed and in September 2014, the Utility submitted a report to the NRC and the CPUC's Independent Peer Review Panel that confirmed the seismic safety of the plant. The Independent Review Panel is providing comments on the report and the Utility expects its review to be completed within the next six to eight months. (See also "Environmental Matters" and Item 1A. Risk Factors.)

[2] The Utility's hydroelectric system consists of 107 generating units at 67 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for three small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years.

[3] The Utility's larger operational photovoltaic facilities include the Five Points solar station (15 MW), the Westside solar station (15 MW), the Stroud solar station (20 MW), the Huron solar station (20 MW), the Cantua solar station (20 MW), the Giffen solar station (10 MW), the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). All of these facilities are located in Fresno County, except for the Guernsey solar station, which is located in Kings County.

*Generation Resources from Third Parties.* The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. (See "Ratemaking Mechanisms" above.) For more information regarding the Utility's power purchase agreements, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

***Electricity Transmission***

At December 31, 2014, the Utility owned approximately 18,100 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 91 electric transmission substations with a capacity of approximately 63,400 MVA. The Utility's electric transmission system is interconnected with electric power systems in the

Western Electricity Coordinating Council, which includes many western states, Alberta and British Columbia, and parts of Mexico.

In November 2013, the Utility, MidAmerican Transmission, LLC, and Citizens Energy Corporation were selected by the CAISO to jointly develop a new 230-kV transmission line to address the growing power demand in Fresno, Madera and Kings counties area. The 70-mile line will connect the Utility-owned and -operated Gates and Gregg substations. The new line will help reduce the number and duration of power outages, improve voltage in the area, support economic development, and bolster efforts to integrate clean, renewable energy onto the grid. The transmission line is expected to commence operations by 2022, and could come online earlier.

Throughout 2014, the Utility upgraded several critical substations and re-conductored a number of transmission lines to improve maintenance and system flexibility, reliability and safety. The Utility expects to undertake various additional transmission projects over the next several years to upgrade and expand the capacity of its transmission system to accommodate system load growth, secure access to renewable generation resources, replace aging or obsolete equipment and improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment.

***Electricity Distribution***

The Utility's electricity distribution network consists of approximately 141,700 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 55 transmission switching substations, and 603 distribution substations, with a capacity of approximately 30,200 MVA. The Utility’s distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility’s customers.

These distribution substations serve as the central hubs for the Utility’s electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. In October 2014, the Utility commenced operations at the first of three new electric distribution control centers. This 24,000-square foot, state-of-the-art facility, located in Fresno, California, will enhance electric reliability and resiliency for the Utility’s customers throughout the Central Valley and will utilize current and future Smart Grid technologies. Additional facilities in Rocklin and Concord, California, are expected to be completed in 2015 and 2016, respectively. These control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2014, the Utility replaced approximately 295,000 feet of underground cable, replaced approximately 975,000 feet of overhead wire, and installed or replaced 20 distribution substation transformer banks to improve reliability and provide capacity to accommodate growing demand. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2015.

*Electricity Operating Statistics*

The following table shows certain of the Utility's operating statistics from 2012 to 2014 for electricity sold or delivered, including the classification of revenues by type of service.

| | | 2014 | | 2013 | | 2012 |
|---|---|---|---|---|---|---|
| Customers (average for the year) | | 5,276,025 | | 5,243,216 | | 5,214,170 |
| Deliveries (in GWh) [(1)] | | 86,303 | | 86,513 | | 86,113 |
| Revenues (in millions): | | | | | | |
| Residential | $ | 4,784 | $ | 5,091 | $ | 4,953 |
| Commercial | | 5,141 | | 4,905 | | 4,735 |
| Industrial | | 1,543 | | 1,388 | | 1,408 |
| Agricultural | | 1,172 | | 1,021 | | 901 |
| Public street and highway lighting | | 79 | | 75 | | 79 |
| Other [(2)] | | (172) | | (128) | | (11) |
| Subtotal | | 12,547 | | 12,352 | | 12,065 |
| Regulatory balancing accounts [(3)] | | 1,109 | | 137 | | (51) |
| **Total operating revenues** | **$** | **13,656** | **$** | **12,489** | **$** | **12,014** |
| Selected Statistics: | | | | | | |
| Average annual residential usage (kWh) | | 6,458 | | 6,752 | | 5,961 |
| Average billed revenues per kWh: | | | | | | |
| Residential | $ | 0.1603 | $ | 0.1643 | $ | 0.1594 |
| Commercial | | 0.1585 | | 0.1499 | | 0.1449 |
| Industrial | | 0.0998 | | 0.0928 | | 0.917 |
| Agricultural | | 0.1516 | | 0.1454 | | 0.1458 |
| Net plant investment per customer | $ | 6,339 | $ | 6,002 | $ | 4,919 |

(1) These amounts include electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
(2) This activity is primarily related to a remittance of revenue to the Department of Water Resources ("DWR") (the Utility acts as a billing and collection agent on behalf of the DWR), partially offset by other miscellaneous revenue items.
(3) These amounts represent revenues authorized to be billed. The 2014 activity represents an increase to balancing account receivable primarily related to the adoption of the 2014 GRC.

**Natural Gas Utility Operations**

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e., natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as core transport agents). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more than 91% of core customers, representing nearly 80% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers (i.e., outside of the Utility's service territory) and to third-party natural gas storage customers.

*Natural Gas Supplies*

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility also is supplied by natural gas fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated generally based on market conditions. During 2014, the Utility purchased approximately 269,590 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 17% of the total natural gas volume the Utility purchased during 2014.

*Natural Gas System Assets*

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 2014, the Utility's natural gas system consisted of approximately 42,700 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport this gas from the U.S Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border, and firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport this natural gas from supply points in the U.S. Southwest to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas system in the area of Daggett, California. For more information regarding the Utility's natural gas transportation agreements, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's transmission system. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later withdrawal. In addition, four independent storage operators are interconnected to the Utility's northern California transmission system.

The Utility also owns and operates a 42,000-square-foot control center in San Ramon, California to monitor and control all aspects of its natural gas system across its service area.

During 2014, the Utility completed its system-wide replacement of 847 miles of cast iron natural gas distribution pipeline with plastic pipe. Additionally, the Utility conducted an annual system-wide review of its transmission pipeline class location designations. As part of its distribution integrity management program, during 2014 the Utility completed inspections of approximately 35,000 sewer laterals.

Since work began on the PSEP and other gas transmission work in 2011, the Utility has validated the maximum allowable operating pressure for all of its transmission pipelines through records verification; accomplished four-year goal of strength testing or records validation of 783 miles of transmission pipeline; replaced 127 miles of transmission pipeline; automated 208 valves; and collected and digitized more than 3.8 million pipeline records.

### *Natural Gas Operating Statistics*

The following table shows the Utility's operating statistics from 2012 through 2014 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Customers (average for the year) | 4,394,283 | 4,378,797 | 4,353,278 |
| Gas purchased (MMcf) | 202,215 | 240,414 | 247,792 |
| Average price of natural gas purchased | $ 4.09 | $ 3.29 | $ 2.45 |
| Bundled gas sales (MMcf): | | | |
| Residential | 143,514 | 181,775 | 185,376 |
| Commercial | 42,080 | 46,668 | 47,341 |
| **Total Bundled Gas Sales** | **185,594** | **228,443** | **232,717** |
| Revenues (in millions): | | | |
| Bundled gas sales: | | | |
| Residential | $ 1,683 | $ 1,870 | $ 1,852 |
| Commercial | 419 | 395 | 383 |
| Other | 51 | 44 | 66 |
| Bundled gas revenues | 2,153 | 2,309 | 2,301 |
| Transportation service only revenue | 662 | 555 | 499 |
| Subtotal | 2,815 | 2,864 | 2,800 |
| Regulatory balancing accounts | 617 | 240 | 221 |
| **Total operating revenues** | **$ 3,432** | **$ 3,104** | **$ 3,021** |
| Selected Statistics: | | | |
| Average annual residential usage (Mcf) | 34 | 44 | 45 |
| Average billed bundled gas sales revenues per Mcf: | | | |
| Residential | $ 11.72 | $ 10.29 | $ 9.99 |
| Commercial | 9.96 | 8.47 | 8.09 |
| Net plant investment per customer | $ 2,468 | $ 2,234 | $ 1,696 |

## Competition

### *Competition in the Electricity Industry*

California law allows qualifying non-residential customers of investor-owned electric utilities to purchase electricity from energy service providers other than the regulated utilities, (referred to as “direct access”) up to certain annual and overall GWh limits that have been specified for each utility.

The Utility’s customers may, under certain circumstances, obtain power from a CCA instead of from the Utility. California law permits cities and counties and certain other public agencies to generate and/or purchase electricity for their local residents and businesses after they have registered as CCAs and submitted an Implementation Plan to the CPUC. Under these arrangements, the Utility continues to provide transmission, distribution, metering, and billing services to the customers of the CCAs and remains the electricity provider of last resort for those customers. The law provides that a CCA can procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. The Utility is able to recover from each CCA any costs of implementing the program that are reasonably attributable to the CCA, and to recover from all customers any costs of implementing the program not reasonably attributable to a CCA.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, seek to acquire the Utility’s distribution facilities, either under a consensual transaction, or via eminent domain.

The Utility is also subject to increased competition due to the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits at the full retail rate, are increasing.

### *Competition in the Natural Gas Industry*

The Utility primarily competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

## Environmental Regulation

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of carbon monoxide ($CO_2$) and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. (See Item 1A. Risk Factors.) Generally, the Utility has recovered most of the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a special ratemaking mechanism described in Note 14: Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in Item 8.

### *Hazardous Waste Compliance and Remediation*

The Utility's facilities are subject to the requirements of the federal Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (CERCLA). The Utility is also subject to the regulations adopted by the EPA, the federal agency responsible for implementing the federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under CERCLA these persons (known as “potentially responsible parties”) may be jointly and severally liable for the costs of cleaning up the hazardous substances, paying for the harm caused to natural resources, and paying for the costs of required health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the California Department of Toxic Substances Control, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 14: Commitments and Contingencies–Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in Item 8.

### *Air Quality and Climate Change*

The Utility's electricity generation plants, natural gas pipeline operations, fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, $CO_2$, sulfur dioxide ($SO_2$), mono-nitrogen oxide ($NO_x$), particulate matter, and other GHG emissions.

In December 2009, the EPA concluded that GHG emissions contribute to climate change and issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. In May 2014, the United States released its third National Climate Assessment, which stated that the global climate is changing and that impacts related to climate change are already evident in many sectors and are expected to become increasingly disruptive across the nation throughout this century and beyond.

*Federal Regulation*. At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

In January 2014, the EPA published draft regulations under section 111(b) of the Clean Air Act to control $CO_2$, the most common GHG, from new fossil fuel-fired power plants. While these draft regulations as presently written do not apply to the Utility's power plants, it is possible that the final regulations may affect the design, construction, operation and cost of future fossil fuel-fired power plants. The EPA is expected to issue final regulations in 2015.

In June 2014, the EPA published draft federal regulations under section 111(d) of the Clean Air Act that are designed to reduce $CO_2$ emissions from existing fossil fuel-fired power plants on a national basis by as much as 30% by 2030, compared with 2005 levels. The EPA is expected to issue final regulations in 2015. As proposed, once the EPA has finalized regulations, states have up to two or three years to submit final plans depending on whether they work alone or in partnership with other states, and up to 15 years for full implementation of all emission reduction measures. It is uncertain whether and how these federal regulations will ultimately impact California, since existing state regulation currently requires, among other things, the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. As described below, the Utility expects all costs and revenues associated with the state-wide, comprehensive cap-and-trade program to be passed through to customers.

*State Regulation.* California law requires the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to implement AB 32, including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy. The cap–and-trade program's first compliance period, which began on January 1, 2013, applied to the electricity generation and large industrial sectors. The next compliance period, which began on January 1, 2015, expanded to include the natural gas and transportation sectors, effectively covering all the economy's major sectors until 2020. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Emitters may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owners, and farmers) that occur outside of the emitters' facilities through CARB-qualified offset projects such as reforestation or biomass projects. The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers. The California RPS program that requires the utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California.

*Climate Change Mitigation and Adaptation Strategies.* During 2014, the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to plan for the actions that it will need to take to adapt to the likely impacts of climate change on the Utility's future operations. The Utility regularly reviews the most relevant scientific literature on climate change such as sea level rise, temperature changes, rainfall and runoff patterns, and wildfire risk, to help the Utility identify and evaluate climate change-related risks and develop the necessary adaptation strategies. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme, persistent, and frequent hot weather. The Utility believes its strategies to reduce GHG emissions—through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage—are effective strategies for adapting to the expected increase in demand for electricity. The Utility's vegetation management activities also reduce the risk of wildfire impacts on electric and gas facilities. Over the long-term, the Utility also faces the risk of higher flooding potential at coastal and low elevation facilities due to sea level rise.

Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. This could, in turn, affect the Utility's hydroelectric generation. To plan for this potential change, the Utility is engaging with state and local stakeholders and also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and developing new modeling tools for forecasting runoff.

With respect to natural gas operations, both safety-related pipeline strength testing and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and volume of natural gas within pipelines prior to venting. In addition, the Utility continues to replace a substantial portion of its older cast iron, steel and plastic distribution pipelines and steel gas transmission mains with new pipe, which reduces leakage.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2013 totaled more than 57 million metric tonnes of $CO_2$-e, two-thirds of which came from natural gas use. The following table shows the 2013 GHG emissions data the Utility reported to the CARB under AB 32. PG&E Corporation and the Utility publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| Source | Amount (metric tonnes $CO_2$ – equivalent) |
|---|---|
| Fossil Fuel-Fired Plants [1] | 2,382,463 |
| Natural Gas Compressor Stations [2] | 325,701 |
| Distribution Fugitive Natural Gas Emissions | 213,858 |
| Customer Natural Gas Use [3] | 43,506,493 |

[1] Includes nitrous oxide and methane emissions from the Utility's generating stations.
[2] Includes compressor stations emitting more than 25,000 metric tonnes of $CO_2$-e annually.
[3] Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, including entities that have their own compliance obligation under AB 32. The Utility's compliance obligation under AB 32 (discussed above under "State Regulation") applies to the combustion of natural gas delivered to customers other than customers that have their own compliance obligation. Excluding the GHG emissions of entities that have their own compliance obligation, the Utility's GHG emissions for 2013 were approximately 19 million metric tonnes, as calculated by the CARB.

The following table shows the Utility's third-party-verified $CO_2$ emissions rate associated with the electricity delivered to customers in 2013 as compared to the national and California averages for electric utilities:

| | Amount (Pounds of $CO_2$ per MWh) |
|---|---|
| U.S. Average [1] | 1,232 |
| California's Average [1] | 611 |
| Pacific Gas and Electric Company [2] | 427 |

[1] Source: EPA eGRID.
[2] Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's emissions rate.

### *Air Emissions Data for Utility-Owned Generation*

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised approximately 36.4% of the Utility's delivered electricity in 2013. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | 2013 | 2012 |
|---|---|---|
| Total $NO_x$ Emissions (tons) | 153 | 158 |
| $NO_x$ Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total $SO_2$ Emissions (tons) | 17 | 15 |
| $SO_2$ Emissions Rate (pounds/MWh) | 0.0011 | 0.0009 |

### *Water Quality*

On May 19, 2014, the EPA issued final regulations to implement the requirements of the federal Clean Water Act that require cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. The federal regulations provide more flexibility in complying with some of the Clean Water Act's requirements. Various industry and environmental groups have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Fourth Circuit. California's once-through cooling policy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The California Water Board has appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014 and the board is expected to issue a final decision regarding Diablo Canyon's compliance with the state policy in 2015. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

The final requirements of the federal and state cooling water policies could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (See "Diablo Canyon Power Plant" in Item 3. Legal Proceedings below.)

### *Nuclear Fuel Disposal*

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until such time as the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. The settlement agreement also provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. In 2013 and 2014, the Utility was awarded an additional $50 million for costs incurred between 2011 and July 2014. These proceeds are being refunded to customers through rates. The settlement agreement, as amended, does not address costs incurred for spent fuel storage beyond 2016 and such costs could be subject to future litigation. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

## ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. (Also see Cautionary Language Regarding Forward-Looking Statements in Item 7. MD&A.) In addition to other disclosures within this Form 10-K, including MD&A in Item 7 and Note 2: Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Item 8 and other documents filed with the SEC from time to time, the following key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility. Such factors could affect actual results of operations and cause results to differ substantially from historical results or from results that are currently sought.

### Risks Related to the Outcome of Enforcement Matters, Investigations, and Regulatory Proceedings

***PG&E Corporation's and the Utility's financial results could be materially affected by the outcomes of the CPUC investigative enforcement proceedings pending against the Utility, the federal criminal prosecution of the Utility, and the investigations and other potential enforcement matters discussed in Item 7. MD&A.***

In September 2014, the CPUC ALJs overseeing the three investigative enforcement proceedings against the Utility issued a decision to impose total penalties of $1.4 billion on the Utility based on their findings that the Utility committed approximately 3,700 violations of natural gas regulations. The Utility and other parties have appealed these decisions. (See "Enforcement and Litigation Matters – Pending CPUC Investigations" in Item 7. MD&A.) The CPUC could issue a final decision that imposes a materially higher amount of penalties. The impact on PG&E Corporation's and the Utility's consolidated financial statements will vary depending on the forms and amounts of penalties imposed.

Further, if the Utility is convicted of the pending federal criminal charges, the Utility could be required to pay a material amount of fines. Based on the superseding indictment's allegations, the maximum alternative fine would be approximately $1.13 billion. (See "Enforcement and Litigation Matters – Federal Criminal Indictment" in Item 7. MD&A.) The Utility also could incur a material amount of costs to comply with remedial measures that the CPUC or a federal judge may impose on the Utility, such as a requirement that the Utility's natural gas operations be supervised by a third-party monitor.

The CPUC could impose penalties or take other enforcement action with respect to communications that may have violated the CPUC's rules regarding ex parte communications (See "Enforcement and Litigation Matters – Improper CPUC Communications" in Item 7. MD&A.) In response to the Utility's violations of the CPUC's rules regarding ex parte communications relating to the 2015 GT&S rate case, the CPUC issued a decision to disallow up to the entire amount of incremental revenues that would have been collected from ratepayers over the five-month period between March 2015 and August 2015. The exact amount of the revenue disallowance will be determined in the CPUC's final decision in the 2015 GT&S rate case. See "Ratemaking and Other Regulatory Proceedings – 2015 Gas Transmission and Storage Rate Case" in Item 7. MD&A. Federal and state law enforcement authorities have begun investigations in connection with these matters and they could take enforcement action in the future. The Utility could be subject to additional penalties or reputational harm if it fails to comply with the restrictions on communications between the Utility and the CPUC imposed by the CPUC in November 2014.

In addition, the Utility could incur material charges, including fines and other penalties, in connection with the new CPUC investigation of the Utility's compliance with natural gas distribution record-keeping practices, the self-reports the Utility has submitted to the CPUC in accordance with the SED's gas safety citation program, the SED's audit findings, the other matters discussed in "Enforcement and Litigation Matters" in Item 7. MD&A, and other self-reports the Utility may file under the gas safety program or under the new electric safety program.

The Utility could be subject to additional regulatory or governmental enforcement action with respect to compliance with federal, state or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and resource adequacy requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; and federal electric reliability standards. The amount of such fines, penalties, or customer refunds could have a material effect on PG&E Corporation's and the Utility's financial results.

***PG&E Corporation's and the Utility's financial results depend upon the amount of revenues the Utility is authorized to collect through rates and the Utility's ability to manage its operating expenses so that it is able to earn its authorized rate of return in a timely manner.***

As a regulated entity, the Utility's rates are set by the CPUC or the FERC on a prospective basis and are generally designed to allow the Utility to collect sufficient revenues to recover the costs of providing service, including a return on and of its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; general economic conditions and potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and affordable electric and gas services. As the Utility's reputation continues to suffer from the negative media coverage of the ongoing enforcement proceedings, the risk of adverse regulatory outcomes may increase. In addition, the restrictions on communications between the Utility and the CPUC imposed by the CPUC in November 2014 prevent the Utility from fully participating in the regulatory process, which, in turn may affect regulatory outcomes. The Utility's relationship with the CPUC also may be negatively affected depending on what, if any, future action may be taken, or negative media coverage that may be generated, in response to the release of approximately 65,000 emails between the Utility and the CPUC to the CPUC and the City of San Bruno.

In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial results could be materially affected if the Utility's actual costs to safely and reliably serve its customers differ from authorized or forecast costs. The Utility may incur additional costs for many reasons including changing market circumstances, unanticipated events (such as storms, accidents, catastrophic or other events affecting the Utility's operations), or compliance with new state laws or policies. Although the Utility may be allowed to recover some or all of the additional costs, there may be a substantial time lag between when the Utility incurs the costs and when the Utility is authorized to collect revenues to recover such costs. Alternatively, the CPUC or the FERC may disallow costs that they determine were not reasonably or prudently incurred by the Utility.

The Utility's ability to recover its costs also may be affected by the economy and the economy's corresponding impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers or the level of uncollectible bills could increase. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base.

Changes in commodity prices also may have an adverse effect on the Utility's ability to timely recover its operating costs and earn its authorized ROE. Although the Utility generally recovers its electricity and natural gas procurement costs from customers as "pass-through" costs, a significant and sustained rise in commodity prices could create overall rate pressures that make it more difficult for the Utility to recover its costs that are not categorized as "pass-through" costs. To relieve some of this upward rate pressure, the CPUC could authorize lower revenues than the Utility requested or disallow full cost recovery. Further, should the deployment of new electricity generation and energy storage technologies spread and become more cost-effective, the Utility's ability to recover its investments and earn its authorized ROE could be adversely affected unless rates are appropriately adjusted. Also, a confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service, which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments.

***PG&E Corporation's and the Utility's future financial results could be materially affected by the extent to which its natural gas transmission costs exceed authorized revenues and whether the Utility is able to continue using regulatory accounting for its natural gas transmission business.***

The Utility's ability to recover its natural gas transmission and storage costs in 2015, 2016, and 2017 and earn its authorized ROE will be materially affected by the amount of revenues the CPUC ultimately authorizes the Utility to collect in the 2015 GT&S rate case proceeding. (See "Ratemaking and Other Regulatory Proceedings" in Item 7. MD&A.) In addition, the Utility plans to perform certain work during 2015 through 2017, including work to complete projects under the PSEP and to identify and remove encroachments from gas transmission pipeline rights-of-way. The Utility has not sought to recover the costs it incurs to perform this work. Actual costs to perform this work could materially exceed forecasts and negatively affect PG&E Corporation's and the Utility's results of operations. The Utility expects that it will continue to incur costs to respond to public opposition to the Utility's work to remove trees and other encroachments. The media attention to the Utility's encroachment work also may negatively affect the Utility's reputation.

If rates in the 2015 GT&S rate case and future rate cases are not set at a level that allows the Utility to recover the cost of providing natural gas transmission service and a reasonable return on its investment in future periods, the Utility may be required to discontinue the application of regulatory accounting to its natural gas transmission business. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8 as well as "Critical Accounting Policies" in Item 7. MD&A.) If that occurs, the regulatory assets and liabilities that do not qualify for regulatory accounting treatment would be charged against income in the period in which that determination was made and these charges could have a material impact on PG&E Corporation's and the Utility's financial results. In addition, if regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or gain recognition.

***PG&E Corporation's and the Utility's financial results depend upon the Utility's continuing ability to recover "pass-through" costs, including electricity and natural gas procurement costs, from customers in a timely manner. The CPUC may disallow procurement costs for a variety of reasons. In addition, the Utility's ability to recover these costs could be affected by the loss of Utility customers and decreased new customer growth, if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch" and prudent administration of power purchase agreements in compliance with its CPUC-approved long-term procurement plan. The CPUC could disallow procurement costs incurred by the Utility if the CPUC determines that the Utility did not comply with these principles or if the Utility did not comply with its procurement plan. Further, the contractual prices for electricity under the Utility's power purchase agreements could become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to adverse economic conditions or the loss of the Utility's customers to other generation providers. Despite original CPUC approval of the contracts, the CPUC could disallow contract costs if it determines that the costs are unreasonably above market. The Utility also could incur a CPUC disallowance and/or liability to the counterparties under its contracts to procure electricity from conventional and renewable generation resources if such resources are physically curtailed by the CAISO during periods of over-generation when generation resources scheduled with the CAISO exceed customer load.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by the whether the wholesale electricity market in California continues to function effectively. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended which could result in excessive market prices. The CPUC could prohibit the Utility from passing through the higher costs of electricity to customers. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's then-newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth that occurs through municipalization of the Utility's facilities, an increase in the number of CCAs who provide electricity to their residents, and an increase in the number of consumers who become direct access customers of alternative generation providers. (See "Competition in the Electric Industry" in Item 1.) As the number of bundled customers (i.e., those primarily residential customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase as the Utility would have a smaller customer base from which to recover its procurement costs. Although the Utility is permitted to collect non-bypassable charges for generation-related costs incurred on behalf of former customers, as well as charges for distribution, metering, or other services the Utility continues to provide to such customers, the charges may not be sufficient for the Utility to fully recover the costs to provide these services. In addition, the Utility's ability to collect non-bypassable charges has been, and may continue to be, challenged by certain customer groups. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, could put upward rate pressure on remaining customers. Also, a confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments. If the number of the Utility's customers decreases or grows at a slower rate than anticipated, the Utility's level of capital investment would likely decline as well, in turn leading to a slower growth in rate base and earnings. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy

efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could adversely impact PG&E Corporation's and the Utility's financial results.

PG&E Corporation's and the Utility's financial results could be materially affected if the Utility is unable to recover a material portion of its procurement costs and/or if the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, the wide deployment of distributed generation, and the development of new electricity generation and energy storage technologies.

**Risks Related to Liquidity and Capital Requirements**

***PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.***

PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend on many factors, including the ultimate outcome of the matters discussed under "Enforcement and Litigation Matters" in Item 7. MD&A., the ultimate amount of costs the Utility incurs but does not recover through rates, and the outcome of pending and future ratemaking proceedings. These outcomes in turn can affect PG&E Corporation's and the Utility's credit ratings and outlook. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, volatility in electricity or natural gas prices, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about the CPUC investigations, the criminal investigations, the criminal prosecution, and the other pending enforcement matters. Their negative reputations and continuing uncertainty surrounding the outcomes of these matters may undermine investors' confidence in management's ability to execute its business strategy and restore a constructive regulatory environment. As a result, investors may be less willing to buy shares of PG&E Corporation common stock resulting in a lower stock price. Further, the market price of PG&E Corporation common stock could decline materially after the outcomes are determined. The amount and timing of future share issuances also could affect the stock price. Declines in the stock price would increase the dilutive effect of future stock issuances and make it more difficult or expensive for PG&E Corporation to complete future equity offerings.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation and PG&E Corporation could be required to contribute capital to the Utility to enable the Utility to fulfill its obligation to serve. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

***PG&E Corporation's ability to meet its debt service and other financial obligations and to pay dividends on its common stock depends on the Utility's earnings and cash flows.***

PG&E Corporation is a holding company with no revenue generating operations of its own. The Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. Under the CPUC's rules applicable to utility holding companies, the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company and PG&E Corporation's Board of Directors give "first priority" to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC has interpreted this "first priority" obligation to include the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." In addition, before the Utility can pay common stock dividends to PG&E Corporation, the Utility must maintain its authorized capital structure with an average 52% equity component.

Depending on the outcome of the CPUC investigations, criminal prosecution, and other enforcement matters pending against the Utility, future issuances of PG&E Corporation common stock may materially dilute EPS. (See "Liquidity and Financial Resources" in Item 7. MD&A.) Further, if PG&E Corporation were required to infuse the Utility with significant capital or if the Utility was unable to distribute cash to PG&E Corporation, or both, PG&E Corporation may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend or meet other obligations.

PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%.

**Risks Related to Operations and Information Technology**

***The operations of the Utility's electricity and natural gas generation, transmission, and distribution facilities is inherently dangerous and involves significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial results, and the Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. (See "Utility Operations" in Item 1. Business.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives. The Utility's ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond the Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events (such as the San Bruno accident discussed in Item 7. MD&A.);
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wild land fire or natural gas explosion), and the failure to respond effectively to a catastrophic event;
- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wild land and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;
- operator or other human error;
- construction performed by third parties, such as ground excavation or "dig-ins" that damage the Utility's underground facilities;
- the release of hazardous or toxic substances into the air, water, or soil; and
- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war.

The occurrence of any of these events could interrupt fuel supplies; affect demand for electricity or natural gas; cause unplanned outages or reduce generating output; damage the Utility's assets or operations; damage the assets or operations of third parties on which the Utility relies; damage property owned by customers or others; and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, to compensate third parties, or to pay penalties or implement remedial measures. These costs may not be recoverable through rates or insurance and could have a material impact of PG&E Corporation's financial results and reputation. As an example, see the discussion in Item 7. MD&A. of the Utility's unrecovered pipeline-related costs incurred since the San Bruno accident.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities or the construction or demolition or facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial

results. Future insurance coverage may not be available at rates and on terms as favorable as the Utility's current insurance coverage or may not be available at all.

***The Utility's operational and information technology systems could fail to function properly or be damaged by third parties (including cyber-attacks and acts of terrorism), severe weather, natural disasters, or other events. Any of these events could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense or liability to third parties.***

The operation of the Utility's extensive electricity and natural gas systems rely on evolving information and operational technology systems and network infrastructures that are becoming more complex as new technologies and systems are implemented to modernize capabilities to safely and reliably deliver gas and electric services. The Utility's ability to serve its customers requires the continued operation of complex information technology systems and network infrastructure that are interconnected with the systems and infrastructure owned by third parties. The Utility's business is highly dependent on its ability to process and monitor, on a daily basis, a very large number of tasks and transactions, many of which are highly complex. Despite implementation of security measures, all of the Utility's technology systems are vulnerable to disability or failures due to hacking, viruses, acts of war or terrorism and other causes. The failure of the Utility's information and operational systems and networks due to a physical attack, cyber-attack or other cause could significantly disrupt operations; cause harm to the public or employees; result in outages or reduced generating output; damage the Utility's assets or operations or those of third parties; and subject the Utility to claims by customers or third parties, any of which could have a material effect on PG&E Corporation's and the Utility's financial results.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require ongoing maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. The Utility often relies on third-party vendors to maintain, modify, and update its systems and these third-party vendors could cease to exist. Any disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification or implementation of new systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively affect the effectiveness of the Utility's control environment, and/or the Utility's ability to timely file required regulatory reports.

In addition, the Utility's information systems contain confidential information, including information about customers and employees. The theft, damage, or improper disclosure of confidential information can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, reduce the value of proprietary information, and harm the Utility's reputation.

***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire.***

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. The operation of the nuclear facilities also depends on the availability of adequate fuel supplies. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial results. In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

In addition, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow and that future changes in legislation, regulations, orders, or their interpretation, could result in the Utility ceasing operations at Diablo Canyon before the licenses expire. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial results.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See "Regulatory Environment" in Item 1. Business.) If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to

cease operations until it can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon before the licenses expire.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial results could be materially affected.

**Risks Related to Environmental Factors**

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial results.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. (See Note 14 to the Notes to the Consolidated Financial Statements in Item 8 for more information.)

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. (See "Environmental Regulation" in Item 1.) The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial results. Their financial results also can be materially affected by changes in estimated costs and by the extent to which actual remediation costs differ from recorded liabilities.

***The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.***

The Utility has been studying the potential effects of climate change (increased temperatures, reduced precipitation, rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. Increasing temperatures and lower levels of precipitation in the Utility's service territory would reduce snowpack in the Sierra Mountains. If the levels of snowpack were reduced, the Utility's hydroelectric generation would decrease and the Utility would need to acquire additional generation from other sources at a greater cost. Should the Utility increase

reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, increasing temperatures and lower levels of precipitation could increase the occurrence of wildfires in the Utility's service territory causing damage to the Utility's facilities or the facilities of third parties on which the Utility relies to provide service. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including hydroelectric assets such as dams and canals, and the electric transmission assets that are located on levees throughout the Utility's service territory. The Utility could incur substantial costs to repair or replace facilities, restore service, compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

**Other Risk Factors**

***The Utility may be required to incur substantial costs in order to obtain or renew licenses and permits needed to operate the Utility's business and the Utility may be subject to fines and penalties for failure to comply or obtain license renewal.***

The Utility must comply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility's hydroelectric generation facilities, and those issued by environmental and other federal, state and local governmental agencies. Many of the Utility's capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizations, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility. If a license or permit is not renewed for a particular facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs. Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Utility's compliance costs. In particular, in connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility. In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has not been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, licenses, ordinances, or other requirements, or if the Utility cannot recover the increase in associated compliance and other costs in a timely manner, PG&E Corporation's and the Utility's financial results could be materially affected.

***Poor investment performance or other factors could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. The performance of the debt and equity markets affects the value of plan assets and trust assets. A decline in the market value may increase the funding requirements for these plans and trusts. The cost of providing pension and other postretirement benefits is also affected by other factors, including interest rates used to measure the required minimum funding levels, the rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by the rates of return on trust assets, changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. (See Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in Item 8.) If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans or if actual nuclear decommissioning costs exceed the amount of nuclear decommissioning trust funds and the Utility is unable to recover the contributions or additional costs in rates, PG&E Corporation's and the Utility's financial results could be materially affected.

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility's workforce is aging and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceedings. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under "Electric Utility Operations" and "Natural Gas Utility Operations." The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11.2 million square feet of real property, including 8.8 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire in 2022.

The Utility currently owns approximately 167,000 acres of land, including approximately 140,000 acres of watershed lands. In 2002 the Utility agreed to permanently preserve six "beneficial public values" on all its watershed lands through conservation easements or equivalent protections, and to make up to 44,000 acres of its watershed lands available for donation to public entities or qualified non-profit conservation organizations. The six "beneficial public values" being preserved through these conservation easements include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Pacific Forest Watershed Lands Stewardship Council oversees the implementation of a land conservation plan that articulates the long-term management objectives for these watershed lands. The Utility's goal is to implement all the transactions needed to implement the land conservation plan by the end of 2017, subject to securing all required regulatory approvals.

## ITEM 3. LEGAL PROCEEDINGS

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see "Enforcement and Litigation Matters" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

***Diablo Canyon Power Plant***

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists'

recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

The final requirements of the federal and state cooling water policies (discussed above in Item 1. Business under "Environmental Regulation – Water Quality") could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on the Utility's financial condition or results of operations.

***CPUC Investigations Regarding the Utility's Gas Transmission System and the San Bruno Accident***

There are three CPUC investigative enforcement proceedings pending against the Utility. These investigations relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident.

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in these investigations in which they determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision calling for total penalties of $1.4 billion on the Utility to address all violations, allocated as follows: (1) $950 million fine to be paid to the State General Fund, (2) $400 million refund to ratepayers of previously authorized revenues, and (3) remedial measures that the ALJs estimate will cost the Utility at least $50 million. The presiding officer decisions are not the final decisions of the CPUC. Three of the five CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. In addition, in October 2014, the Utility and other parties, including the SED, TURN, the ORA, the City and County of San Francisco, and the City of San Bruno appealed the presiding officer decisions.

In its appeals, the Utility argued that the penalties imposed and the findings and conclusions on which they are based do not meet applicable legal standards, are based on the misapplication of California law and regulations, and are unconstitutional. The Utility has asked the CPUC to order the Utility to pay a significantly reduced penalty that is reasonable and proportionate in light of the nature of the violations and that takes into account the substantial unrecovered amounts the Utility has already spent and forecasts that it will spend on gas system safety. The Utility requested that it be allowed 180 days to raise the funds it may be ordered to pay to the State General Fund rather than the 40 days specified in the decision. The Utility also argued that the entire penalty should go toward funding investments in the Utility's gas transmission system. TURN, the ORA, and the City and County of San Francisco jointly filed an appeal urging the CPUC to disallow the Utility's recovery of remaining PSEP costs of $877 million and to require the Utility to pay $473 million to the State General Fund. These parties also argue that the record in the investigative proceedings would support an even larger penalty than stated in the decision. The City of San Bruno appealed the rejection of its proposals for the appointment of an independent monitor to oversee the Utility's natural gas operations and for the establishment of a pipeline safety trust. It is uncertain when the final outcome of the investigations will be determined.

While the various appeals and requests for review of the presiding officer decisions are unresolved there continues to be significant uncertainty about the ultimate forms and amounts of penalties (including fines) that will be imposed on the Utility. The impact on PG&E Corporation's and the Utility's Consolidated Financial Statements will depend on the amounts and forms of penalties that are ultimately adopted by the CPUC. For more information, see discussions "Enforcement and Litigation Matters" in Item 7. MD&A and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in Item 8.

***Federal Criminal Indictment***

On July 29, 2014, a federal grand jury in the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts (increased from 12 counts charged in the original indictment) alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges an alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. A status conference is scheduled to be held in court on March 9, 2015. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their consolidated financial statements as such amounts are not considered to be probable.

***Litigation Related to the San Bruno Accident and Natural Gas Spending***

At December 31, 2014, there were also five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits filed a consolidated complaint with the San Mateo County Superior Court in November 2013, which has been amended to add a fourth shareholder plaintiff and to discuss recent events, including the federal criminal indictment discussed above. In August 2014, the judge lifted the stay on the consolidated complaint for the limited purpose of allowing briefing and hearing on demurrers (state court motions to dismiss). On September 15, 2014, PG&E Corporation, the Utility and the individual defendants asked the court to dismiss the consolidated complaint because the plaintiffs (1) failed to demand that the Boards of Directors pursue claims against the defendant directors and officers and (2) have not adequately pled why such demand should be excused. The court has since clarified that the appropriate board on whom the plaintiffs should have demanded with respect to the claims in the operative complaint is the 2013 PG&E Corporation Board of Directors (and the 2014 Board regarding the allegations first raised in plaintiffs' 2014 amended consolidated complaint). The Court has invited plaintiffs to amend their complaint to accommodate this clarification, and defendants to refile a demurrer on this amended complaint if they so choose. Accordingly, briefing and litigation on this motion is expected to continue through the first quarter of 2015. On September 22, 2014, PG&E Corporation, the Utility, and the individual defendants filed a petition with the California Court of Appeal requesting a new order continuing the stay until resolution of the federal criminal indictment discussed above. A fifth purported shareholder derivative lawsuit that was filed in the U.S. District Court for the Northern District of California remains stayed.

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

## EXECUTIVE OFFICERS OF THE REGISTRANTS

The following individuals serve as executive officers [1] of PG&E Corporation and/or the Utility, as of February 10, 2015. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| Anthony F. Earley, Jr. | 65 | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation | September 13, 2011 to present |
| | | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| | | Chairman of the Board and Chief Executive Officer, DTE Energy Company | August 1998 to September 30, 2010 |
| Christopher P. Johns | 54 | President | August 1, 2009 to present |
| | | Senior Vice President, Financial Services | May 1, 2009 to July 31, 2009 |
| | | Senior Vice President and Chief Financial Officer, PG&E Corporation | May 1, 2009 to July 31, 2009 |
| Nickolas Stavropoulos | 56 | Executive Vice President, Gas Operations | June 13, 2011 to present |
| | | Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid | August 2007 to March 31, 2011 |
| Geisha J. Williams | 53 | Executive Vice President, Electric Operations | June 1, 2011 to present |
| | | Senior Vice President, Energy Delivery | December 1, 2007 to May 31, 2011 |

| | | | |
|---|---|---|---|
| Karen A. Austin | 53 | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| | | President, Consumer Electronics, Sears Holdings | February 2009 to May 2011 |
| Desmond A. Bell | 52 | Senior Vice President, Safety and Shared Services | January 1, 2012 to present |
| | | Senior Vice President, Shared Services and Chief Procurement Officer | October 1, 2008 to December 31, 2011 |
| Helen A. Burt | 58 | Senior Vice President, Corporate Affairs | September 18, 2014 to present |
| | | Senior Vice President, Corporate Affairs, PG&E Corporation | September 18, 2014 to present |
| | | Senior Vice President and Chief Customer Officer | February 27, 2006 to September 17, 2014 |
| Loraine M. Giammona | 47 | Senior Vice President and Chief Customer Officer | September 18, 2014 to present |
| | | Vice President, Customer Service | January 23, 2012 to September 17, 2014 |
| | | Regional Vice President, Customer Care, Comcast Cable | November 2002 to January 2012 |
| Edward D. Halpin | 53 | Senior Vice President and Chief Nuclear Officer | April 2, 2012 to present |
| | | President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company | December 2009 to March 2012 |
| Kent M. Harvey | 56 | Senior Vice President and Chief Financial Officer, PG&E Corporation | August 1, 2009 to present |
| | | Senior Vice President, Financial Services | August 1, 2009 to present |
| Gregory K. Kiraly | 50 | Senior Vice President, Electric Distribution Operations | September 18, 2012 to present |
| | | Vice President, Electric Distribution Operations | October 1, 2011 to September 17, 2012 |
| | | Vice President, SmartMeter Operations | August 23, 2010 to September 30, 2011 |
| | | Vice President, Electric Maintenance and Construction | January 1, 2010 to August 22, 2010 |
| Steven E. Malnight | 42 | Senior Vice President, Regulatory Affairs | September 18, 2014 to present |
| | | Vice President, Customer Energy Solutions | May 15, 2011 to September 17, 2014 |
| | | Vice President, Integrated Demand Side Management | July 1, 2010 to May 14, 2011 |
| | | Vice President, Renewable Energy | May 1, 2009 to June 30, 2010 |
| Hyun Park | 53 | Senior Vice President and General Counsel, PG&E Corporation | November 13, 2006 to present |
| John R. Simon | 50 | Senior Vice President, Human Resources | April 16, 2007 to present |
| | | Senior Vice President, Human Resources, PG&E Corporation | April 16, 2007 to present |

| | | | |
|---|---|---|---|
| Jesus Soto, Jr. | 47 | Senior Vice President, Engineering, Construction and Operations | September 16, 2013 to present |
| | | Senior Vice President, Gas Transmission Operations | May 29, 2012 to September 15, 2013 |
| | | Vice President, Operations Services, El Paso Pipeline Group | May 2007 to May 2012 |
| Fong Wan | 53 | Senior Vice President, Energy Procurement | October 1, 2008 to present |
| Dinyar B. Mistry | 53 | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to present |
| | | Vice President and Controller, PG&E Corporation | March 8, 2010 to present |
| | | Vice President and Controller | March 8, 2010 to September 30, 2011 |
| | | Vice President and Chief Risk and Audit Officer | September 16, 2009 to March 7, 2010 |
| | | Vice President and Chief Risk and Audit Officer, PG&E Corporation | August 1, 2009 to March 7, 2010 |

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(1) Mr. Earley, Mr. Johns, Ms. Burt, Mr. Harvey, Mr. Park, and Mr. Simon are executive officers of both PG&E Corporation and the Utility. All other listed officers are executive officers of the Utility only.

## PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of January 27, 2015, there were 61,989 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth on page 128 of this report within "Quarterly Consolidated Financial Data (Unaudited)"in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock Utility appears in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5: Common Stock and Share-Based Compensation − Dividends in Item 8 and in "Liquidity and Financial Resources – Dividends" in Item 7. MD&A.

***Sales of Unregistered Equity Securities***

PG&E Corporation did not make any equity contributions to the Utility during the quarter ended December 31, 2014. The Utility was in compliance with the 52% common equity component of its capital structure authorized by the CPUC and had adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2014.

***Issuer Purchases of Equity Securities***

During the quarter ended December 31, 2014, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2014, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

## ITEM 6. SELECTED FINANCIAL DATA

| (in millions, except per share amounts) | 2014 | 2013 | 2012 | 2011 | 2010 |
|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,090 | $ 15,598 | $ 15,040 | $ 14,956 | $ 13,841 |
| Operating income | 2,450 | 1,762 | 1,693 | 1,942 | 2,308 |
| Income from continuing operations | 1,450 | 828 | 830 | 858 | 1,113 |
| Earnings per common share from continuing operations, basic [(1)] | 3.07 | 1.83 | 1.92 | 2.10 | 2.86 |
| Earnings per common share from continuing operations, diluted | 3.06 | 1.83 | 1.92 | 2.10 | 2.82 |
| Dividends declared per common share [(2)] | 1.82 | 1.82 | 1.82 | 1.82 | 1.82 |
| **At Year-End** | | | | | |
| Common stock price per share | $ 53.24 | $ 40.28 | $ 40.18 | $ 41.22 | $ 47.84 |
| Total assets | 60,127 | 55,605 | 52,449 | 49,750 | 46,025 |
| Long-term debt (excluding current portion) | 15,050 | 12,717 | 12,517 | 11,766 | 10,906 |
| Capital lease obligations (excluding current portion) [(3)] | 69 | 90 | 113 | 212 | 248 |
| Energy recovery bonds (excluding current portion) [(4)] | - | - | - | - | 423 |
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,088 | $ 15,593 | $ 15,035 | $ 14,951 | $ 13,840 |
| Operating income | 2,452 | 1,790 | 1,695 | 1,944 | 2,314 |
| Income available for common stock | 1,419 | 852 | 797 | 831 | 1,107 |
| **At Year-End** | | | | | |
| Total assets | 59,865 | 55,049 | 51,923 | 49,242 | 45,679 |
| Long-term debt (excluding current portion) | 14,700 | 12,717 | 12,167 | 11,417 | 10,557 |
| Capital lease obligations (excluding current portion) [(3)] | 69 | 90 | 113 | 212 | 248 |
| Energy recovery bonds (excluding current portion) [(4)] | - | - | - | - | 423 |

[(1)] See "Summary of Changes in Net Income and Earnings per Share" in Item 7. MD&A.
[(2)] Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources – Dividends" in MD&A in Item 7 and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 in Item 8.
[(3)] The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.
[(4)] The energy recovery bonds matured in December 2012.

**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

**OVERVIEW**

Pacific Gas and Electric Company generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E Corporation is the parent holding company of the Utility. The authorized revenue requirements set by the CPUC in the GRC and GT&S rate cases and by the FERC in TO rate cases provide the Utility an opportunity to earn its authorized rates of return on its "rate base" – the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers. Other than its electric transmission and certain GT&S revenues, the Utility's decoupling of base revenues and sales volume eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand.

The Utility's revenue requirements are set based on forecast costs. Differences between forecast costs and actual costs can occur for numerous reasons, including the volume of new customer connections, the detection and mitigation of emerging safety threats, and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. Generally, differences between actual costs and forecast costs could affect the Utility's ability to earn its authorized return (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations below). However, for certain operating costs, such as costs associated with pension and other employee benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). The Utility also collects additional revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers. Therefore, although these costs can fluctuate, they generally do not impact net income (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). See "Ratemaking Mechanisms" in Item 1 for further discussion.

There may be some types of costs that the CPUC has determined will not be recoverable through rates or for which the Utility does not seek recovery, such as certain pipeline-related costs and fines associated with the Utility's natural gas transmission system. The CPUC could also disallow recovery of costs that it finds were not prudently or reasonably incurred. The timing and amount of the unrecoverable or disallowed costs can materially impact the Utility's net income, as described more fully below.

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

### Summary of Changes in Net Income and Earnings per Share

PG&E Corporation's financial results for 2014 reflect an increase in the Utility's revenues as authorized in the CPUC's final decision issued in the Utility's 2014 GRC on August 14, 2014. (See "Results of Operations" below.)

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS for the year ended December 31, 2014 compared to the prior year (see "Results of Operations" below for additional information):

| (in millions, except per share amounts) | Earnings | EPS (diluted) |
|---|---|---|
| **Income Available for Common Shareholders - 2013** | $ 814 | $ 1.83 |
| Natural gas matters [1] | 176 | 0.43 |
| 2014 GRC expense recovery[2] | 134 | 0.29 |
| Tax benefit - repairs method and forecast change [3] | 115 | 0.24 |
| Growth in rate base earnings [4] | 101 | 0.21 |
| Gain on disposition of SolarCity stock | 27 | 0.06 |
| Regulatory matters [5] | 20 | 0.04 |
| Gas transmission revenues | 8 | 0.02 |
| Uneconomic project and lease termination | 8 | 0.02 |
| Increase in shares outstanding [6] | - | (0.15) |
| Other | 33 | 0.07 |
| **Income Available for Common Shareholders - 2014** | **$ 1,436** | **$ 3.06** |

[1] Represents the decrease in net costs related to natural gas matters during 2014 as compared to 2013. These amounts are not recoverable through rates. See "Results of Operations - Operating and Maintenance" below.
[2] In 2013, the Utility incurred approximately $200 million of expense and $1 billion of capital costs above authorized levels. The 2014 GRC decision authorized revenues that support this higher level of spending in 2014 and throughout the GRC period. The amounts in the table represent the after-tax higher authorized revenue recognized during 2014, for the recovery of these expenses and costs.
[3] Represents the favorable impact of recent IRS guidance and forecast changes based on flow-through ratemaking treatment for federal tax deductions resulting from temporary differences attributable to the accelerated recognition of repairs and certain other property-related costs, as reflected in the revenue requirements authorized in the 2014 GRC decision. See "Income Tax Provision" below.
[4] Represents the impact of the increase in rate base as authorized in various rate cases, including the 2014 GRC, during 2014 as compared to 2013.
[5] Includes customer energy efficiency incentive awards.
[6] Represents the impact of a higher number of weighted average shares of common stock outstanding during 2014 as compared to 2013. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including unrecovered expenses.

### Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materially affected by the following factors:

- *The Outcome of Pending Investigations and Enforcement Matters.* The assigned CPUC ALJs overseeing the three pending investigations regarding the Utility's gas transmission system and the San Bruno accident have issued decisions to impose total fines and disallowances of $1.4 billion on the Utility. The Utility and other parties have appealed the decisions and several Commissioners have requested reviews of the decisions. It is uncertain when the final outcome of these investigations will be determined. At December 31, 2014, the Consolidated Balance Sheets included an accrual of $200 million for the minimum amount of fines deemed probable. There is also a pending federal criminal indictment against the Utility alleging that the Utility knowingly and willfully violated the Pipeline Safety Act and illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. Based on the superseding indictment's allegations, the maximum statutory fine would be $14 million and the maximum alternative fine would be approximately $1.13 billion. Federal and state authorities also are conducting investigations in connection with certain communications between the Utility and CPUC personnel. Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to these and other enforcement matters. (See "Enforcement and Litigation Matters" below.)

- *The Timing and Outcome of Ratemaking Proceedings*. In the GT&S rate case the Utility has requested that the CPUC authorize revenue requirements for the Utility's gas transmission and storage operations from 2015 through 2017. The Utility has requested an increase in its 2015 revenue requirements of $555 million over the comparable authorized revenues, as well as increases for 2016 and 2017. In response to Utility's violations of the CPUC's rules regarding ex parte communications relating to the 2015 GT&S rate case, the CPUC issued a decision to disallow some GT&S incremental revenues that may otherwise be authorized in the final decision which is scheduled to be issued in August 2015. The Utility and other parties have filed applications requesting the CPUC to reconsider this decision. It is uncertain whether this decision will be upheld and what amount of revenue requirements will ultimately be authorized in the final GT&S rate case decision. It is also uncertain whether the final outcome of the pending CPUC investigations will affect the outcome of the 2015 GT&S rate case. In addition, the Utility has a TO rate case pending at the FERC. (See "Ratemaking and Other Regulatory Proceedings" below.) The outcome of regulatory proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors discussed in Item 1A. Risk Factors.

- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows could be materially affected if the Utility's actual costs differ from the amounts authorized in the final 2014 GRC decision and future rate case decisions. During the quarter ended December 31, 2014, the Utility recorded a charge of $116 million for the increase in the Utility's forecast of PSEP capital expenditures that are expected to exceed authorized amounts. The Utility could incur additional charges in the future if the forecast of PSEP-related capital expenditures increases. The Utility also forecasts that in 2015 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million, including costs to perform continuing work under the Utility's PSEP and other gas transmission safety work, as well as legal and other expenses. Actual costs could be higher. The final outcome of the pending CPUC investigations and the CPUC enforcement actions with respect to the Utility's violations of the ex parte communication rules also could affect the ultimate amount of unrecovered costs.

- *The Amount and Timing of the Utility's Financing Needs.* PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In 2014, PG&E Corporation issued $802 million of common stock and made equity contributions to the Utility of $705 million. PG&E Corporation forecasts that it will continue issuing a material amount of equity to support the Utility's capital expenditures and to fund unrecovered pipeline-related costs. PG&E Corporation expects that it will issue additional common stock to fund its equity contributions to enable the Utility to pay fines and compliance costs as may be required by the final outcomes of the CPUC investigations, the criminal proceeding, and the other enforcements matters. These additional issuances could have a material dilutive effect on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" below, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this 2014 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Cautionary Language Regarding Forward Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2014, 2013, and 2012. See "Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows" above for further discussion about factors that could affect future results of operations.

### PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders:

| (in millions) | 2014 | 2013 | 2012 |
|---|---|---|---|
| Consolidated Total | $ 1,436 | $ 814 | $ 816 |
| PG&E Corporation | 17 | (38) | 19 |
| Utility | $ 1,419 | $ 852 | $ 797 |

PG&E Corporation's net income or loss consists primarily of interest expense on long-term debt, other income or loss from investments, and income taxes. In 2014, PG&E Corporation's operating results increased reflecting $45 million of realized gains and associated tax benefits recognized in connection with an equity investment in SolarCity. PG&E Corporation's operating results in 2013 reflected an impairment loss of $28 million on its tax equity fund investments and higher charitable contributions as compared to 2012.

### Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2014, 2013 and 2012. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

The Utility's operating results for 2014 reflect the increase in authorized revenues effective January 1, 2014 that was approved by the CPUC in the 2014 GRC decision issued on August 14, 2014. (See "Utility Revenues and Costs that Impacted Earnings" below.)

| | 2014 | | | 2013 | | | 2012 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Revenues and Costs: | | | Revenues and Costs: | | | Revenues and Costs: | | |
| (in millions) | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
| Electric operating revenues | $ 7,059 | $ 6,597 | $13,656 | $ 6,465 | $ 6,024 | $12,489 | $ 6,414 | $ 5,600 | $12,014 |
| Natural gas operating revenues | 2,072 | 1,360 | 3,432 | 1,776 | 1,328 | 3,104 | 1,772 | 1,249 | 3,021 |
| **Total operating revenues** | **9,131** | **7,957** | **17,088** | **8,241** | **7,352** | **15,593** | **8,186** | **6,849** | **15,035** |
| Cost of electricity | - | 5,615 | 5,615 | - | 5,016 | 5,016 | - | 4,162 | 4,162 |
| Cost of natural gas | - | 954 | 954 | - | 968 | 968 | - | 861 | 861 |
| Operating and maintenance | 4,247 | 1,388 | 5,635 | 4,374 | 1,368 | 5,742 | 4,563 | 1,482 | 6,045 |
| Depreciation, amortization, and decommissioning | 2,432 | - | 2,432 | 2,077 | - | 2,077 | 1,928 | 344 | 2,272 |
| **Total operating expenses** | **6,679** | **7,957** | **14,636** | **6,451** | **7,352** | **13,803** | **6,491** | **6,849** | **13,340** |
| **Operating income** | **2,452** | **-** | **2,452** | **1,790** | **-** | **1,790** | **1,695** | **-** | **1,695** |
| Interest income [(1)] | | | 8 | | | 8 | | | 6 |
| Interest expense [(1)] | | | (720) | | | (690) | | | (680) |
| Other income, net [(1)] | | | 77 | | | 84 | | | 88 |
| **Income before income taxes** | | | 1,817 | | | 1,192 | | | 1,109 |
| Income tax provision [(1)] | | | 384 | | | 326 | | | 298 |
| **Net income** | | | 1,433 | | | 866 | | | 811 |
| Preferred stock dividend requirement [(1)] | | | 14 | | | 14 | | | 14 |
| **Income Available for Common Stock** | | | **$ 1,419** | | | **$ 852** | | | **$ 797** |

[(1)] These items impacted earnings.

### Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2014, 2013 and 2012, focusing on revenues and expenses that impacted earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased $890 million or 11% in 2014 compared to 2013. This amount includes an increase to base revenues of $460 million as authorized by the CPUC in the 2014 GRC decision. The GRC decision also resulted in higher base revenues of $150 million in 2014 related primarily to the DOE settlement in 2012 for spent nuclear fuel storage costs. (See "Ratemaking and Other Regulatory Proceedings" below.) The total increase in operating revenues also includes approximately $150 million, consisting of revenues authorized by the CPUC for recovery of nuclear decommissioning costs and certain PSEP-related costs and revenues authorized by the FERC in the TO rate case. The Utility also collected higher gas transmission revenues driven by increased demand for gas-fired generation.

The Utility's electric and natural gas operating revenues increased $55 million or 1% in 2013 compared to 2012, primarily due to an increase of $294 million as authorized in various rate cases, partially offset by a decrease in revenues of $196 million as a result of the lower ROE authorized by the CPUC in the 2013 Cost of Capital proceeding.

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings decreased $127 million or 3% in 2014 compared to 2013 and $189 million or 4% in 2013 compared to 2012, primarily due to lower net costs incurred in connection with natural gas matters shown in the table below. These decreases were offset by higher benefit-related expenses and other operating expenses of $120 million in 2014 as compared to 2013 and $53 million in 2013 as compared to 2012. Additionally, the Utility incurred an $88 million charge in 2012 for an increase in estimated environmental remediation costs associated with the Hinkley natural gas

compressor station site, with no comparable charge taken in 2013.

The following table provides a summary of the Utility's costs associated with natural gas matters that are not recoverable through rates:

| (in millions) | 2014 | 2013 | 2012 | Cumulative December 31, 2014 |
|---|---|---|---|---|
| Pipeline-related expenses [(1)] | $ 347 | $ 387 | $ 477 | $ 1,757 |
| Disallowed capital expenditures [(2)] | 116 | 196 | 353 | 665 |
| Accrued fines [(3)] | 12 | 22 | 17 | 251 |
| Third-party liability claims [(4)] | (7) | 110 | 80 | 558 |
| Insurance recoveries [(5)] | (112) | (70) | (185) | (466) |
| Contribution to City of San Bruno | - | - | 70 | 70 |
| **Total natural gas matters** | **$ 356** | **$ 645** | **$ 812** | **$ 2,835** |

(1) In 2014, the Utility incurred $149 million of PSEP-related expenses, $155 million of other gas safety-related work, and $43 million of legal and other expenses. From December 31, 2010 through December 31, 2014, the Utility incurred respective expenses of $885 million, $502 million, and $370 million. See "Enforcement and Litigation Matters" below.

(2) Amounts represent charges for PSEP capital costs expected to exceed the authorized amount. See "Pipeline Safety Enhancement Plan" in Note 14 of the Consolidated Financial Statements in Item 8.

(3) Includes fines related to ex parte communications, the Carmel incident, and other fines. See "Pending CPUC Investigations" below. The Utility has paid $40 million of fines through December 31, 2014.

(4) Amounts represent third-party liability claims and associated legal costs. The Utility's liability for third-party claims related to the San Bruno accident was reduced in 2014 to reflect the settlement of all outstanding third-party claims. Since the San Bruno accident, the Utility has made cumulative settlement payments of $532 million through December 31, 2014.

(5) The Utility has recognized insurance recoveries for third-party claims and associated legal costs. The Utility has been engaged in settlement negotiations with its insurers regarding recovery of its remaining claims and costs.

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased $355 million or 17% in 2014 compared to 2013 and $149 million or 8% in 2013 compared to 2012. In 2014, the increase was primarily due to higher depreciation rates as authorized by the CPUC in the 2014 GRC decision and higher nuclear decommissioning expense reflecting the year-to-date increase as authorized by the CPUC in the nuclear decommissioning triennial proceeding. Additionally, depreciation, amortization, and decommissioning expenses were impacted by an increase in capital additions during 2014 as compared to 2013, and during 2013 as compared to 2012.

*Interest Income, Interest Expense, and Other Income, Net*

There were no material changes to interest income, interest expense, and other income, net for the periods presented.

*Income Tax Provision*

The Utility's revenue requirements for 2014 through 2016, as authorized in the 2014 GRC decision, reflect flow-through ratemaking for income tax expense benefits attributable to the accelerated recognition of repair costs and certain other property-related costs for federal tax purposes. PG&E Corporation and the Utility's effective tax rates for 2014 are lower as compared to 2013, and are expected to remain lower in 2015 and 2016 due to these temporary differences that are now being flowed through. PG&E Corporation and the Utility's 2014 financial results reflect a reduction in income tax expense associated with these temporary differences. (See Note 8 of the Notes to the Consolidated Financial Statements in Item 8.)

The Tax Increase Prevention Act, signed into law on December 19, 2014, extended 50% bonus federal tax depreciation on qualified property placed into service in 2014. The Utility's earnings were not impacted by the incremental tax depreciation as the flow-through ratemaking discussed above does not apply and the 2014 GRC decision requires the Utility to refund to customers the estimated cost of service benefits associated with this tax law change.

The Utility's income tax provision increased $58 million or 18% in 2014 as compared to 2013 and $28 million or 9% in 2013 as compared to 2012. The increase in the tax provision was primarily due to higher pre-tax income, partially offset by certain reductions in tax expense for flow-through treatment as discussed above.

The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

| | 2014 | | 2013 | | 2012 | |
|---|---|---|---|---|---|---|
| Federal statutory income tax rate | 35.0 | % | 35.0 | % | 35.0 | % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) (1) | 1.6 | | (2.2) | | (3.0) | |
| Effect of regulatory treatment of fixed asset differences (2) | (14.7) | | (3.8) | | (3.9) | |
| Tax credits | (0.7) | | (0.4) | | (0.6) | |
| Benefit of loss carryback | (0.8) | | (1.0) | | (0.4) | |
| Non deductible penalties | 0.3 | | 0.7 | | 0.5 | |
| Other, net | 0.4 | | (0.9) | | (0.8) | |
| **Effective tax rate** | **21.1** | **%** | **27.4** | **%** | **26.8** | **%** |

(1) Includes the effect of state flow-through ratemaking treatment.
(2) Represents effect of federal flow-through ratemaking treatment including those deductions related to repairs and certain other property-related costs discussed above.

**Utility Revenues and Costs that did not Impact Earnings**

*Cost of Electricity*

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The volume of power purchased by the Utility is driven by customer demand, the availability of the Utility's own generation facilities (including hydroelectric generations), and the cost effectiveness of each source of electricity. Additionally, the cost of electricity is impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with California law.

| **(in millions)** | | 2014 | | 2013 | | 2012 |
|---|---|---|---|---|---|---|
| Cost of purchased power | $ | 5,266 | $ | 4,696 | $ | 3,873 |
| Fuel used in own generation facilities | | 349 | | 320 | | 289 |
| **Total cost of electricity** | **$** | **5,615** | **$** | **5,016** | **$** | **4,162** |
| Average cost of purchased power per kWh | $ | 0.101 | $ | 0.094 | $ | 0.079 |
| **Total purchased power (in millions of kWh)** | | **52,008** | | **49,941** | | **48,933** |

*Cost of Gas*

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, changes in customer demand, and by costs associated with complying with California's GHG laws.

| **(in millions)** | **2014** | **2013** | **2012** |
|---|---|---|---|
| Cost of natural gas sold | $ 813 | $ 807 | $ 676 |
| Transportation cost of natural gas sold | 141 | 161 | 185 |
| **Total cost of natural gas** | **$ 954** | **$ 968** | **$ 861** |
| Average cost per Mcf of natural gas sold | $ 4.37 | $ 3.54 | $ 2.91 |
| **Total natural gas sold (in millions of Mcf)** [(1)] | **186** | **228** | **232** |

[(1)] One thousand cubic feet

*Operating and Maintenance Expenses*

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2014, 2013 and 2012, no material amounts were incurred above authorized amounts.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term debt and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect related to its debt financing costs. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock (see "Ratemaking Mechanisms" in Item 1). The Utility's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters, fines imposed in connection with the pending CPUC investigations and other matters described in "Enforcement and Litigation Matters" below, and certain environmental remediation costs. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends, primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and borrowings and repayments under its revolving credit facility. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of the pending enforcement and litigation matters. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, the majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. During 2014, PG&E Corporation sold 11 million shares of common stock for cash proceeds of $496 million, net of commissions of $4 million, under an equity distribution agreement. There were no sales during the fourth quarter of 2014. In addition, during 2014, PG&E Corporation sold 8 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $306 million.

The proceeds from these equity issuances were used for general corporate purposes, including the contribution of equity into the Utility. For the year ended December 31, 2014, PG&E Corporation made equity contributions to the Utility of $705 million to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC. These equity issuances have been dilutive to PG&E Corporation's EPS to the extent that the proceeds were used by the Utility to restore equity that has been reduced by unrecoverable costs and charges.

PG&E Corporation forecasts that it will issue additional common stock to fund the Utility's equity needs. PG&E Corporation forecasts that it will issue between $400 million and $600 million in common stock during 2015, excluding amounts attributable to fines the Utility may be required to pay in connection with final outcomes of the CPUC investigations, the criminal proceeding, and other enforcements matters. Future issuances of common stock by PG&E Corporation to fund equity contributions could continue to have a material dilutive effect on EPS depending upon the ultimate outcomes of the matters described in "Enforcement and Litigation Matters" below and the outcome of the GT&S rate case as described in "Ratemaking and Other Regulatory Proceedings" below.

### Cash and Cash Equivalents

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See Note 12 of the Notes to the Consolidated Financial Statements in Item 8.)

**Revolving Credit Facilities and Commercial Paper Programs**

At December 31, 2014, PG&E Corporation and the Utility had $300 million and $2.6 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, these revolving credit facilities include usual and customary provisions regarding events of default and covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. At December 31, 2014, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

**2014 Debt Financings**

PG&E Corporation and the Utility issued $2.3 billion in long-term debt and $300 million in short-term debt during the year ended December 31, 2014. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

**Dividends**

The Board of Directors of PG&E Corporation and the Utility have authority to declare dividends on their respective common stock. Dividends are not payable unless and until declared by the applicable Board of Directors. The CPUC requires that the Utility maintain, on average, its authorized capital structure including a 52% equity component and that the PG&E Corporation Board of Directors give first priority to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. Each Board of Directors retains authority to change the common stock dividend rate at any time, especially if unexpected events occur that would change their view as to the prudent level of cash conservation.

The Board of Directors of PG&E Corporation declared and paid common stock dividends of $0.455 per share for each of the quarters in 2014, 2013, and 2012, for annual dividends of $1.82 per share. The Utility's Board of Directors declared and paid common stock dividends in the aggregate amount of $179 million to PG&E Corporation for each of the quarters in 2014, 2013, and 2012. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends.

The following table summarizes PG&E Corporation's and the Utility's dividends paid:

| (in millions) | 2014 | 2013 | 2012 |
|---|---|---|---|
| **PG&E Corporation:** | | | |
| Common stock dividends paid | $ 802 | $ 782 | $ 746 |
| Common stock dividends reinvested in Dividend Reinvestment and Stock Purchase Plan | 21 | 22 | 22 |
| **Utility:** | | | |
| Common stock dividends paid | $ 716 | $ 716 | $ 716 |
| Preferred stock dividends paid | 14 | 14 | 14 |

Additionally, in December 2014, the following dividends were declared:

- the Board of Directors of PG&E Corporation declared quarterly common stock dividends of $0.455 per share, totaling $217 million, of which approximately $211 million was paid in January 2015 to shareholders of record on December 31, 2014;
- the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable in February 2015, to shareholders of record on January 30, 2015.

Subject to the outcome of the matters described in "Enforcement and Litigation Matters" below, PG&E Corporation expects that its Board will continue to maintain the current quarterly common stock dividend. (See Item 1A. Risk Factors.)

**PG&E Corporation**

PG&E Corporation affiliates previously entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that were considered VIEs. On July 2, 2014, PG&E Corporation disposed of its interest in the tax equity agreements for $87 million and has no remaining commitment to fund these agreements. Sales proceeds, lease payments, investment contributions, benefits, and customer payments received were included in cash flows from operating and investing activities within the Consolidated Statements of Cash Flows to coincide with the applicable lease structure.

**Utility**

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for 2014, 2013, and 2012 were as follows:

| (in millions) | 2014 | 2013 | 2012 |
|---|---|---|---|
| Net income | $ 1,433 | $ 866 | $ 811 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,432 | 2,077 | 2,272 |
| Allowance for equity funds used during construction | (100) | (101) | (107) |
| Deferred income taxes and tax credits, net | 731 | 1,103 | 684 |
| PSEP disallowed capital expenditures | 116 | 196 | 353 |
| Other | 226 | 299 | 236 |
| Effect of changes in operating assets and liabilities: | (1,219) | (1,024) | 679 |
| **Net cash provided by operating activities** | **$ 3,619** | **$ 3,416** | **$ 4,928** |

During 2014, net cash provided by operating activities increased by $203 million as compared to 2013. This increase was primarily due to $500 million in net tax refunds received during 2014 as compared to $62 million in net tax payments made during 2013, $160 million in additional GHG auction proceeds during 2014 as compared to 2013, and $137 million in additional collateral returned to the Utility in 2014 as compared to 2013. The increase was offset by higher purchased power costs of $599 million (see "Cost of Electricity" within "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above) and various fluctuations in other cash flows.

During 2013, net cash provided by operating activities decreased by $1.5 billion as compared to 2012 when the Utility collected $460 million from customers related to the energy recovery bonds which matured at the end of 2012. In addition, in 2013, the amount of cash collateral returned to the Utility by third parties was $243 million lower than in 2012, the payments the Utility received under the DOE settlement for reimbursement of the Utility's spent nuclear fuel disposal costs was $221 million lower, net of legal fees, than the Utility received in 2012, and the Utility's tax payments were $236 million higher than in 2012. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of fines or penalties that will be imposed in connection with the pending investigations and other enforcement matters, as well as any costs associated with remedial actions the Utility may be required to implement (see "Enforcement and Litigation Matters" below);
- the timing and amount of pipeline-related costs the Utility incurs, but does not recover, associated with its natural gas system (see "Operating and Maintenance" within "Results of Operations – Utility Revenues and Costs that Impacted Earnings" above);
- the volatility in energy commodity costs and seasonal load;
- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments; and
- the timing of the resolution of the Chapter 11 disputed claims and the related refunds passed through to customers (see Note 12 of the Notes to the Consolidated Financial Statements in Item 8).

***Investing Activities***

The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. The amount and timing of the Utility's capital expenditures is affected by many factors such as the approvals of the CPUC, FERC, and other regulatory agencies, the volume of new customer connections, and the occurrence of storms that cause outages or damages to the Utility's infrastructure. The funds in the nuclear decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's cash flows from investing activities for 2014, 2013, and 2012 were as follows:

| **(in millions)** | **2014** | **2013** | **2012** |
|---|---|---|---|
| Capital expenditures | $ (4,833) | $ (5,207) | $ (4,624) |
| Decrease in restricted cash | 3 | 29 | 50 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,336 | 1,619 | 1,133 |
| Purchases of nuclear decommissioning trust investments | (1,334) | (1,604) | (1,189) |
| Other | 29 | 21 | 16 |
| **Net cash used in investing activities** | **$ (4,799)** | **$ (5,142)** | **$ (4,614)** |

Net cash used in investing activities decreased by $343 million in 2014 compared to 2013 due to a decrease of $374 million in capital expenditures. This decrease was primarily due to lower PSEP-related capital expenditures and the absence of additional investment in the Utility's photovoltaic program.

Net cash used in investing activities increased by $528 million in 2013 compared to 2012 due to an increase of $583 million in capital expenditures, partially offset by net proceeds associated with sales of nuclear decommissioning trust investments in 2013 as compared to net purchases of nuclear decommissioning trust investments in 2012.

Future cash flows used in investing activities primarily depend on the timing and amount of capital expenditures. The Utility forecasts that it will incur $5.5 billion in capital expenditures in 2015 and between $5.3 billion and $5.8 billion in 2016. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases.

*Financing Activities*

The Utility's financing activities are impacted by the conditions in the capital markets and the maturity date of existing debt instruments. The Utility forecasts that its financing needs will increase as it incurs non-recoverable pipeline-related costs and fines associated with the pending investigations and other enforcement matters.

The Utility's cash flows from financing activities for 2014, 2013, and 2012 were as follows:

| (in millions) | 2014 | 2013 | 2012 |
|---|---|---|---|
| Net issuances (repayments) of commercial paper, net of discount | $ (583) | $ 542 | $ (1,021) |
| Proceeds from issuance of short-term debt, net of issuance costs | 300 | - | - |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs | 1,961 | 1,532 | 1,137 |
| Short-term debt matured | - | - | (250) |
| Repayments of long-term debt | (539) | (861) | (50) |
| Energy recovery bonds matured | - | - | (423) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution from PG&E Corporation | 705 | 1,140 | 885 |
| Other | 56 | (26) | 28 |
| **Net cash provided by (used in) financing activities** | **$ 1,170** | **$ 1,597** | **$ (424)** |

In 2014, net cash provided by financing activities decreased by $427 million compared to the same period in 2013. In 2013, net cash provided by financing activities increased by $2.0 billion compared to 2012. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depends on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities.

**CONTRACTUAL COMMITMENTS**

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2014:

| | Payment due by period | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **Less Than 1 Year** | **1-3 Years** | **3-5 Years** | **More Than 5 Years** | **Total** |
| **Utility** | | | | | |
| Long-term debt [(1)]: | $ 714 | $ 2,304 | $ 2,870 | $ 21,779 | $ 27,667 |
| Purchase obligations [(2)]: | | | | | |
| Power purchase agreements: | 3,566 | 6,839 | 6,239 | 33,896 | 50,540 |
| Natural gas supply, transportation, and storage | 544 | 271 | 214 | 648 | 1,677 |
| Nuclear fuel agreements | 138 | 260 | 224 | 429 | 1,051 |
| Pension and other benefits [(3)] | 388 | 776 | 776 | 388 | 2,328 |
| Operating leases [(2)] | 44 | 76 | 57 | 183 | 360 |
| Preferred dividends [(4)] | 14 | 28 | 28 | - | 70 |
| **PG&E Corporation** | | | | | |
| Long-term debt [(1)]: | 8 | 16 | 359 | - | 383 |
| **Total Contractual Commitments** | **$ 5,416** | **$ 10,570** | **$ 10,767** | **$ 57,323** | **$ 84,076** |

[(1)] Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2014 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)
[(2)] See Note 14 of the Notes to the Consolidated Financial Statements in Item 8.
[(3)] See Note 11 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years"

represents only 1 year of contributions for the Utility's pension and other benefit plans.
[4] Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

The contractual commitments table above excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 8 of the Notes to the Consolidated Financial Statements in Item 8.

**Off-Balance Sheet Arrangements**

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 14 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) in Item 8.

**ENFORCEMENT AND LITIGATION MATTERS**

Since the San Bruno accident occurred on September 9, 2010, PG&E Corporation and the Utility have incurred total cumulative charges of approximately $2.8 billion related to natural gas matters that are not recoverable through rates. See "Results of Operations" above.

**Pending CPUC Investigations**

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in the three investigative enforcement proceedings pending against the Utility related to the Utility's natural gas transmission operations and practices and the San Bruno accident. The ALJs determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision calling for total fines and disallowances of $1.4 billion on the Utility to address all violations, allocated as shown in the table below. The ALJs' decisions are not the final decisions of the CPUC. Three CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. In addition, the Utility and other parties, including the SED, TURN, the ORA, the City and County of San Francisco, and the City of San Bruno have appealed the presiding officer decisions. (For additional information, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.) It is uncertain when the final outcome of the investigations will be determined.

While the various appeals and requests for review of the presiding officer decisions are unresolved there continues to be significant uncertainty about the ultimate forms and amounts of penalties (including fines) that will be imposed on the Utility. At December 31, 2014, the Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable. The impact on PG&E Corporation's and the Utility's Consolidated Financial Statements will depend on the amounts and forms of penalties that are ultimately adopted by the CPUC. Fines payable to the State General Fund or refunds of revenues would be charged to net income when it is probable that such fines or refunds will be imposed and the amounts can be reasonably estimated. A disallowance of previously authorized and incurred capital costs would be charged to net income when the disallowance is probable and the amount can be reasonably estimated. Penalties in the form of future disallowed costs would be charged to net income in the period during which the actual costs are incurred. Although PG&E Corporation and the Utility believe it is probable that the CPUC will impose total penalties materially in excess of the $200 million previously accrued, they are unable to make a better estimate due to the variety of potential combinations of amounts and forms of penalties that could ultimately be imposed on the Utility and uncertainty about the timing of recognition. PG&E Corporation and the Utility believe the final outcome of the investigations will have a material impact on their financial condition, results of operations, and cash flows.

If the presiding officer joint decision becomes final, the Utility estimates that its total pre-tax unrecovered costs and fines related to natural gas transmission operations would be about $4.85 billion based on current forecasts, allocated as follows:

| Description of Component: | | Amounts (in millions) |
|---|---|---|
| Fine payable to the State General Fund | $ | 950 |
| Refund of revenues previously authorized | | 400 |
| Additional estimated unrecoverable costs (1) | | 50 |
| **Total penalty** | | **1,400** |
| PSEP costs previously disallowed | | 635 |
| **Total penalty and PSEP cost disallowance** | | **2,035** |
| Gas pipeline safety costs incurred or committed (2) | | 2,800 |
| Less: Credit for PSEP costs previously disallowed | | (635) |
| Total estimated shareholder impact before non-deductibility of fines | | **4,200** |
| Estimated impact of non-deductibility of fines for tax purposes (3) | | 650 |
| **Total estimated shareholder impact (pre-tax)** | **$** | **4,850** |

(1) The presiding officer joint decision estimates that the Utility would incur at least $50 million to implement remedial measures. Actual costs could differ materially based on the scope and timing of work. In addition, the decision requires shareholders to reimburse intervenors for legal and litigation expenses.
(2) Actual and forecast costs for gas pipeline safety work in 2010 and beyond that will not be recovered through rates, including previously disallowed PSEP capital and expense. This amount includes charges of $665 million, including an additional charge of $116 million recorded during the three months ended December 31, 2014, for PSEP capital costs that are forecasted to exceed the authorized amounts.
(3) Estimated impact calculated based on the Utility's statutory tax rate.

**Federal Criminal Indictment**

On July 29, 2014, a federal grand jury in the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts (increased from 12 counts charged in the original indictment) alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges an alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. A status conference is scheduled to be held in court on March 9, 2015. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their consolidated financial statements as such amounts are not considered to be probable.

**Other Enforcement Matters**

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters.

*Improper CPUC Communications*

On September 15, 2014, the Utility notified the CPUC and the ALJ overseeing the 2015 GT&S rate case that it believes certain communications between the Utility and CPUC personnel relating to the 2015 GT&S rate case violated the CPUC's rules regarding ex parte communications. Ex parte communications include any communication between a decision maker and an interested person concerning substantive issues in certain identified categories of formal proceedings before the CPUC. (The Utility discovered the communications as part of an internal review of communications between the Utility and the CPUC undertaken after the City of San Bruno filed a motion at the CPUC in late July 2014 alleging that various email communications

between the Utility's employees and CPUC personnel violated the ex parte communication rules with respect to the pending CPUC investigative enforcement proceedings against the Utility. The Utility believes that the communications cited by San Bruno in its July 2014 motion are not prohibited ex parte communications. The CPUC has not yet addressed San Bruno's motion and its request that the CPUC penalize the Utility.)

On November 20, 2014, the CPUC issued a decision imposing a fine of $1.05 million on the Utility and disallowing up to the entire amount of the revenue increase that would have been collected from ratepayers over the five-month period between March 2015 and August 2015. The exact amount of the revenue disallowance will be determined in the CPUC's final decision in the GT&S rate case expected to be issued in August 2015. In addition, the decision prohibits the Utility from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors in any rate-setting or adjudicatory proceeding and requires the Utility to report communications with senior CPUC staff, in any rate-setting proceeding or adjudicatory proceeding before the CPUC, for one year from the effective date of the decision. With respect to the GT&S rate case, the ban will be in effect until the resolution of the GT&S rate case or one year from the effective date of the decision, whichever is later. The Utility and other parties have requested that the CPUC reconsider its decision. The ORA, TURN, and the City of San Bruno argue that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million. It is uncertain when the CPUC will address these applications for rehearing. (See "Ratemaking and Other Regulatory Proceedings" below.)

In October and December 2014, the Utility notified the CPUC of additional email communications between the Utility and CPUC personnel regarding various matters (not limited to the GT&S rate case), that the Utility believes may constitute or describe ex parte communications. As of January 30, 2015, the Utility had provided copies of approximately 65,000 email communications between the CPUC and the Utility to the CPUC and the City of San Bruno. It is uncertain whether any of these email communications will be challenged as prohibited ex parte communications or as improper or illegal.

The Utility believes it is probable that CPUC enforcement actions will be taken in connection with these additional ex parte communications but is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties. It is also possible that other parties may request that the CPUC rescind decisions or take other action in open or closed proceedings to address ex parte communications that they may allege occurred regarding substantive issues in those proceedings. For example, TURN and the ORA have filed petitions to request that the CPUC rescind a $29 million shareholder incentive awarded to the Utility in 2010 for the successful implementation of the Utility's 2006-2008 energy efficiency programs based on their allegation that prohibited ex parte communications tainted the decision. It is uncertain whether the CPUC will grant these petitions or whether parties will request the CPUC to take action in other proceedings. It is also uncertain whether the ex parte communication issues will affect the outcome of other pending legal matters, ratemaking or regulatory proceedings, investigations and enforcement matters.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office have begun investigations in connection with these communications. The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility.

*Gas Safety Citation Program*

The SED, the division of the CPUC primarily responsible for overseeing the safety of electric and natural gas utility operations in California, conducts periodic audits of the Utility's operating practices and investigates potential violations. In December 2011, the CPUC adopted a gas safety citation program and delegated authority to the SED to issue citations and impose fines on California gas corporations, such as the Utility, for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. (As required by state law, a similar program for electric safety became effective on an interim basis on January 1, 2015. For more information, see "Regulatory Environment" in Item 1.) The California gas corporations are required to inform the SED of self-identified or self-corrected violations. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken.

Since the gas safety program became effective, the Utility has filed approximately 84 self-reports and the SED has imposed fines ranging from $50,000 to $16.8 million (including the $10.85 million fine related to an explosion in Carmel, California that is discussed below) for violations identified through self-reports, SED investigations and audits. The SED recently has stated that it will not conduct further investigations into 65 self-reports the Utility had filed through December 31, 2014. The Utility believes it is probable that the SED will impose fines or take other enforcement action with respect to some of the Utility's remaining self-reports or other self-reports that the Utility has filed since January 1, 2015. The Utility believes it is reasonably possible that the SED will impose fines on the Utility based on allegations of noncompliance that are contained in some of the

SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

*Carmel Incident*

On March 3, 2014, a vacant house in Carmel, California was severely damaged due to a natural gas explosion while the Utility's employees were performing work to upgrade the main natural gas distribution pipeline in the area. There were no injuries or fatalities. The SED conducted an investigation of the incident and alleged that the Utility committed two violations of certain natural gas safety regulations by failing to follow procedures to update records, to provide its welding crew with accurate information, and to take steps to make safe any actual or potential hazard to life or property. On November 20, 2014, the SED issued a citation to the Utility that included a fine of $10.85 million for these alleged violations. The Utility recorded this amount as an expense for 2014. The Utility has appealed the citation to the CPUC. The SED has requested that the CPUC dismiss the Utility's appeal as untimely. The CPUC has not yet addressed the SED's request. In addition, the Utility was informed that the U.S. Attorney's Office was investigating the Carmel incident. It is uncertain whether any charges will be brought against the Utility.

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC issued an order instituting a new investigation into whether the Utility violated applicable laws pertaining to record-keeping practices for its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found.

In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014. (See "Carmel Incident" above.) On December 22, 2014, as directed by the CPUC, the Utility submitted a report that explained why the Utility believes the SED's investigative findings do not constitute violations of law and also outlined the various programs, measures and actions the Utility has undertaken to continuously improve its distribution record keeping practices.

PG&E Corporation and the Utility believe it is reasonably possible that the CPUC will impose fines on the Utility or take other enforcement action in connection with this matter, but are unable to reasonably estimate the amount or range of future loss contingencies.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

**Other Pending Lawsuits and Claims**

At December 31, 2014, there were also five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits filed a consolidated complaint with the San Mateo County Superior Court in November 2013, which has been amended to add a fourth shareholder plaintiff and to discuss recent events, including the federal criminal indictment discussed above. In August 2014, the judge lifted the stay on the consolidated complaint for the limited purpose of allowing briefing and hearing on demurrers (state court motions to dismiss). On September 15, 2014, PG&E Corporation, the Utility and the individual defendants asked the court to dismiss the consolidated complaint because the plaintiffs (1) failed to demand that the Boards of Directors pursue claims against the defendant directors and officers and (2) have not adequately pled why such demand should be excused. The court has since clarified that the appropriate

board on whom the plaintiffs should have demanded with respect to the claims in the operative complaint is the 2013 PG&E Corporation Board of Directors (and the 2014 Board regarding the allegations first raised in plaintiffs' 2014 amended consolidated complaint). The Court has invited plaintiffs to amend their complaint to accommodate this clarification, and defendants to refile a demurrer on this amended complaint if they so choose. Accordingly, briefing and litigation on this motion is expected to continue through the first quarter of 2015. On September 22, 2014, PG&E Corporation, the Utility, and the individual defendants filed a petition with the California Court of Appeal requesting a new order continuing the stay until resolution of the federal criminal indictment discussed above. A fifth purported shareholder derivative lawsuit that was filed in the U.S. District Court for the Northern District of California remains stayed.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

**RATEMAKING AND OTHER REGULATORY PROCEEDINGS**

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

**2015 Gas Transmission and Storage Rate Case**

*Utility's GT&S Request*

In its December 2013 GT&S rate case application, the Utility requested that the CPUC authorize a 2015 revenue requirement of $1.29 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $555 million over currently authorized amounts. The Utility also requested attrition increases of $61 million in 2016 and $168 million in 2017 based on its forecasted capital expenditures and the associated growth in rate base, as well as increasing costs of labor, materials, and other expenses. The Utility requested that the CPUC authorize the Utility's forecast of its 2015 weighted average rate base for its gas transmission and storage business of $3.56 billion, which includes the capital spend above authorized levels for the prior rate case period. The Utility has not requested authorization to recover approximately $150 million of costs it forecasts it will incur over the three-year period to pressure test pipelines placed into service after 1961 that lack records and perform remedial work associated with the Utility's pipeline corrosion control program. The Utility also has not requested authorization to recover costs it forecasts it will incur during 2015 through 2017 to identify and remove encroachments from its gas transmission pipeline rights-of-way.

The Utility also has proposed changes to the revenue sharing mechanism authorized in the last GT&S rate case (covering 2011-2014) that subjected a portion of the Utility's transportation and storage revenue requirement to market risk. The Utility proposed full balancing account treatment that allows for recovery of the Utility's authorized transportation and storage revenue requirements except for the revenue requirement associated with the Utility's 25% interest in the Gill Ranch storage field.

*Intervenors' Recommendations*

The ORA has recommended a 2015 revenue requirement of $1,044 million, an increase of $329 million over authorized amounts, and attrition increases of $39 million for 2016 and $61 million for 2017. The ORA also recommended that the GT&S rate case period be expanded to four years with an attrition increase of $35 million for 2018. The ORA proposed that the CPUC authorize 2015 capital expenditures of $595 million, compared to the Utility's request of $779 million. TURN has stated that it intends to make its revenue requirement recommendation in its opening brief to be filed after hearings conclude on February 27, 2015. Nevertheless, TURN has submitted testimony recommending that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service between January 1, 1956 and June 30, 1961, as well as certain other work that TURN considers to be remedial. TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of these capital expenditures be subject to a reasonableness review and an independent audit. TURN states that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit.

*Procedural Schedule*

Hearings began on February 2, 2015 and are scheduled to end on February 27, 2015. The current procedural schedule calls for a final decision to be issued in August 2015. The CPUC has stated that if a final CPUC decision is issued in the three investigative enforcement proceedings pending against the Utility within the schedule of the 2015 GT&S rate case, the schedule and scope of issues to be considered may be further amended to consider the implications of that decision on the Utility's revenue requirements.

*Order to Show Cause*

On September 15, 2014, the Utility notified the CPUC and the ALJ overseeing the 2015 GT&S rate case that it believes certain communications between the Utility and CPUC personnel relating to the 2015 GT&S rate case violated the CPUC's rules regarding ex parte communications. The CPUC issued an order to show cause why the Utility should not be penalized. On November 20, 2014, the CPUC issued a decision that prohibits the Utility from recovering up to the entire amount of the revenue increase that would have been collected from ratepayers over the five-month period between March 2015 (the date the final decision was originally scheduled to be issued) and August 2015 (the date called for under the revised procedural schedule issued after the Utility's notification of ex parte communications). The decision states that the exact amount of this revenue disallowance will be determined in the CPUC's final decision in the 2015 GT&S rate case. The CPUC also imposed a fine of $1.05 million on the Utility for the violations. (See "Enforcement and Litigation Matters" above regarding additional ex parte communications that were self-reported by the Utility.) The Utility and other parties have filed applications requesting the CPUC to rehear its decision. The ORA, TURN, and the City of San Bruno argue that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million. It is uncertain when the CPUC will address these applications for rehearing.

*Regulatory Accounting*

The Utility's continued use of regulatory accounting under GAAP (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) for gas transmission and storage service depends on its ability to recover its cost of service. The Utility's ability to recover its costs of providing gas transmission and storage service will be affected by the outcome of the 2015 GT&S rate case and future GT&S rate cases. If the Utility were unable to continue using regulatory accounting under GAAP, there would be differences in the timing of expense or gain recognition that could materially affect PG&E Corporation's and the Utility's future financial results.

**Proposal for Electric Vehicle Infrastructure Development**

On February 9, 2015, the Utility filed an application requesting the CPUC to approve the Utility's proposal to deploy, own and maintain EV charging infrastructure in its service territory, including EV retail charging stations, to promote and facilitate the deployment of EVs. Under the Utility's proposal, the Utility would develop EV charging infrastructure over an estimated five years to meet approximately 25% of projected EV charging station needs by 2020. The Utility's EV charging infrastructure is expected to be used in future programs designed to aid the integration of increased intermittent renewable energy on the state's electric power grid. The Utility estimates that it would incur capital costs of $551 million and operating costs of $103 million over the proposed project timeline. The Utility has requested that the CPUC authorize the Utility to collect an average annual revenue requirement over the project development years of $81 million to recover these costs. The Utility has requested that the CPUC issue a decision before the end of 2015.

**FERC Transmission Owner Rate Case**

The Utility has one TO rate case pending at the FERC. The Utility has requested a 2015 retail electric transmission revenue requirement of $1,366 million, a $326 million increase to the currently authorized revenue requirement of $1,039.6 million (The FERC approved the current revenue requirement on November 7, 2014). The proposed rates will be effective March 1, 2015, subject to refund, pending a final decision by the FERC. The Utility's 2015 cost forecasts reflect the continuing need to replace and modernize aging electric transmission infrastructure, to meet the need for increased capacity in the CAISO controlled grid, and to comply with new rules aimed at ensuring the physical and cyber security of the nation's electric system. The Utility forecasts that it will make investments of $975 million in 2014 and $1,125 million in 2015 in various capital projects. The Utility's proposed rate base for 2015 is $5.12 billion, compared to $4.57 billion in 2014. The Utility has requested that the FERC approve an 11.26% ROE. The procedural schedule is currently being held in abeyance while settlement discussions are held.

## ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of $CO_2$ and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Item 1A. Risk Factors and "Environmental Regulation" in Item 1.)

### Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment. At December 31, 2014, $158 million and $291 million was accrued in the Consolidated Balances Sheets for estimated undiscounted remediation costs associated with the Hinkley site and the Topock site, respectively. Costs associated with the Hinkley site are not recovered through rates. (See Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

## RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" (see "Ratemaking Mechanisms" in Item 1) and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

### Commodity Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk.

The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $1 million and $14 million at December 31, 2014 and 2013, respectively. During the 12 months ended December 31, 2014, the Utility's approximate high, low, and average values-at-risk were $9 million, $1 million and $5 million, respectively. During 2013, the value-at-risk amounts were $14 million, $9 million and $12 million, respectively. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.)

### Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2014 and December 31, 2013, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be $9 million and $11 million, respectively, based on net variable rate debt and other

interest rate-sensitive instruments outstanding.

**Energy Procurement Credit Risk**

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility ties many energy contracts to master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's credit risk exposure to its counterparties as of December 31, 2014 and December 31, 2013:

| (in millions) | Gross Credit Exposure Before Credit Collateral [1] | Credit Collateral | Net Credit Exposure [2] | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| December 31, 2014 | $ 88 | $ (18) | $ 70 | 3 | 29 |
| December 31, 2013 | 87 | $ (9) | $ 78 | 2 | 34 |

[1] Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.
[2] Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

## CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

**Regulatory Accounting**

The Utility's rates are primarily set by the CPUC and the FERC and are designed to recover the cost of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods that the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, the Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other reduction of net allowable costs be given to customers over future periods. At December 31, 2014, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $9.0 billion and regulatory liabilities (including current balancing accounts payable) of $7.6 billion. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods 2012 through 2014. If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on its best estimate; to the extent there is a high degree of uncertainty in the Utility's forecast, it will record a provision based on the lower end of the range of possible losses. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors. The Utility recorded charges of $116 million, $196 million, and $353 million in 2014, 2013, and 2012, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. See "Pipeline Safety Enhancement Plan" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8. The additional charge in 2014 primarily reflects costs for Line 109 (that runs through the San Francisco peninsula) mostly related to emergent permitting conditions and requirements, as well as updated estimates for the few remaining PSEP projects. Management will continue to periodically assess its PSEP capital costs and the related CPUC regulatory proceedings, and further charges could be required in future periods.

**Loss Contingencies**

***Environmental Remediation Liabilities***

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former manufactured gas plant sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2014 and 2013, the Utility's accruals for undiscounted gross environmental liabilities were $954 million and $900 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.8 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Legal and Regulatory Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are subject to claims or named as parties in lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amount of such losses, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs. (See "Enforcement and Litigation Matters" and "Legal and Regulatory Contingencies" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

**Asset Retirement Obligations**

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

To estimate its liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2014, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $3.6 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. Additionally, if the inflation adjustment increased 25 basis points, the amount of the ARO would increase by approximately 1.70%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 1.70%.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Pension and other benefit expense is based on the differences between actuarial assumptions and actual plan results and is deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability for a portion of the credit balance in accumulated other comprehensive income. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience,

plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses. During 2014, PG&E Corporation and the Utility adopted the Society of Actuaries 2014 Mortality Tables Report (RP-2014) and Mortality Improvement Scale (MP-2014 with modifications), which adjusted the mortality assumptions used for measuring retirement plan obligations. The updated mortality assumptions reflect increasing life expectancies in the United States, resulting in an increase to PG&E Corporation's and the Utility's pension and PBOP plans' projected benefit obligations. Future pension and postretirement expenses are also expected to increase due to the new mortality assumptions.

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2014 is 7.5%, gradually decreasing to the ultimate trend rate of 3.5% in 2024 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 6.2% compares to a ten-year actual return of 9.3%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 715 Aa-grade non-callable bonds at December 31, 2014. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | | Increase in 2014 Pension Costs | | Increase in Projected Benefit Obligation at December 31, 2014 | |
|---|---|---|---|---|---|---|
| Discount rate | (0.50) | % | $ | 52 | $ | 1,319 |
| Rate of return on plan assets | (0.50) | % | | 62 | | - |
| Rate of increase in compensation | 0.50 | % | | 32 | | 316 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | | Increase in 2014 Other Postretirement Benefit Costs | | Increase in Accumulated Benefit Obligation at December 31, 2014 | |
|---|---|---|---|---|---|---|
| Health care cost trend rate | 0.50 | % | $ | 4 | $ | 53 |
| Discount rate | (0.50) | % | | 3 | | 128 |
| Rate of return on plan assets | (0.50) | % | | 9 | | - |

**NEW ACCOUNTING PRONOUNCEMENTS**

See Note 2 of the Notes to the Consolidated Financial Statements.

**CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS**

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated costs, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the final outcomes of the pending CPUC investigations and enforcement matters, the federal criminal prosecution of the Utility, and the other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, including the ultimate amount of fines imposed, whether a monitor is appointed to oversee the Utility's natural gas operations, and the ultimate amount of costs related to the Utility's natural gas operations that is disallowed or unrecoverable;

- the timing and outcome of additional regulatory enforcement actions or criminal investigations that may be or have been commenced relating to communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are alleged to otherwise be improper, and whether such outcomes or investigations negatively affect the final decisions to be issued in the 2015 GT&S rate case, the pending CPUC investigations, or other ratemaking proceedings;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by negative publicity about the San Bruno accident, the criminal prosecution, the citations issued by the SED against the Utility under the CPUC's gas safety citation program, the state and federal investigations, the CPUC's restrictions on the Utility's communications with the CPUC, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the restrictions on communications between the Utility and the CPUC that have been imposed by the CPUC that, along with continuing public criticism of the Utility and the CPUC, may make it more difficult for the Utility to sustain or repair a constructive working relationship with the CPUC and achieve balanced regulatory outcomes;

- the timing and outcome of ratemaking proceedings (such as the 2015 GT&S rate case and the TO rate case) and whether the cost and revenue forecasts assumed in such outcomes prove to be accurate;

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, the proceeds of which are contributed as equity to maintain the Utility's authorized capital structure as the Utility incurs charges and costs that it cannot recover through rates, including costs and fines associated with natural gas matters and the pending investigations;

- the outcomes of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security; and whether the current or potentially worsening state regulatory environment increases the likelihood of unfavorable outcomes;

- the impact of environmental laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover environmental costs in rates or from other sources; and the ultimate amount of environmental costs the Utility incurs but does not recover, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; and whether the Utility decides to request that the NRC resume processing the Utility's renewal application for the two Diablo Canyon operating licenses, and if so, whether the NRC

grants the renewal;

- the impact of droughts or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;

- the impact of environmental laws and regulations aimed at the reduction of $CO_2$ and GHGs, and whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized ROE;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, especially if the integration of renewable generation resources force conventional generation resource providers to curtail production, triggering "take or pay" provisions in the Utility's power purchase agreements;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the criminal prosecution, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see Item 1A. Risk Factors above. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in MD&A in Item 7 and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| **Operating Revenues** | | | |
| Electric | $ 13,658 | $ 12,494 | $ 12,019 |
| Natural gas | 3,432 | 3,104 | 3,021 |
| **Total operating revenues** | **17,090** | **15,598** | **15,040** |
| **Operating Expenses** | | | |
| Cost of electricity | 5,615 | 5,016 | 4,162 |
| Cost of natural gas | 954 | 968 | 861 |
| Operating and maintenance | 5,638 | 5,775 | 6,052 |
| Depreciation, amortization, and decommissioning | 2,433 | 2,077 | 2,272 |
| **Total operating expenses** | **14,640** | **13,836** | **13,347** |
| **Operating Income** | 2,450 | 1,762 | 1,693 |
| Interest income | 9 | 9 | 7 |
| Interest expense | (734) | (715) | (703) |
| Other income, net | 70 | 40 | 70 |
| **Income Before Income Taxes** | **1,795** | **1,096** | **1,067** |
| Income tax provision | 345 | 268 | 237 |
| **Net Income** | **1,450** | **828** | **830** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 1,436** | **$ 814** | **$ 816** |
| **Weighted Average Common Shares Outstanding, Basic** | **468** | **444** | **424** |
| **Weighted Average Common Shares Outstanding, Diluted** | **470** | **445** | **425** |
| **Net Earnings Per Common Share, Basic** | **$ 3.07** | **$ 1.83** | **$ 1.92** |
| **Net Earnings Per Common Share, Diluted** | **$ 3.06** | **$ 1.83** | **$ 1.92** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2014** | **2013** | **2012** |
| **Net Income** | **$ 1,450** | **$ 828** | **$ 830** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $10, $80, and $72, at respective dates) | (14) | 113 | 108 |
| Net change in investments (net of taxes of $17, $26, and $3 at respective dates) | (25) | 38 | 4 |
| **Total other comprehensive income (loss)** | **(39)** | **151** | **112** |
| **Comprehensive Income** | **1,411** | **979** | **942** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 1,397** | **$ 965** | **$ 928** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2014** | **2013** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 151 | $ 296 |
| Restricted cash | 298 | 301 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $66 and $80 at December 31, 2014 and 2013, respectively) | 960 | 1,091 |
| Accrued unbilled revenue | 776 | 766 |
| Regulatory balancing accounts | 2,266 | 1,124 |
| Other | 377 | 312 |
| Regulatory assets | 444 | 448 |
| Inventories | | |
| Gas stored underground and fuel oil | 172 | 137 |
| Materials and supplies | 304 | 317 |
| Income taxes receivable | 198 | 574 |
| Other | 443 | 611 |
| **Total current assets** | **6,389** | **5,977** |
| **Property, Plant, and Equipment** | | |
| Electric | 45,162 | 42,881 |
| Gas | 15,678 | 14,379 |
| Construction work in progress | 2,220 | 1,834 |
| Other | 2 | 2 |
| **Total property, plant, and equipment** | **63,062** | **59,096** |
| Accumulated depreciation | (19,121) | (17,844) |
| **Net property, plant, and equipment** | **43,941** | **41,252** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 6,322 | 4,913 |
| Nuclear decommissioning trusts | 2,421 | 2,342 |
| Income taxes receivable | 91 | 85 |
| Other | 963 | 1,036 |
| **Total other noncurrent assets** | **9,797** | **8,376** |
| **TOTAL ASSETS** | **$ 60,127** | **$ 55,605** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, 2014 | Balance at December 31, 2013 |
|---|---|---|
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 633 | $ 1,174 |
| Long-term debt, classified as current | - | 889 |
| Accounts payable | | |
| Trade creditors | 1,244 | 1,293 |
| Regulatory balancing accounts | 1,090 | 1,008 |
| Other | 476 | 471 |
| Disputed claims and customer refunds | 434 | 154 |
| Interest payable | 197 | 892 |
| Other | 1,846 | 1,612 |
| **Total current liabilities** | **5,920** | **7,493** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 15,050 | 12,717 |
| Regulatory liabilities | 6,290 | 5,660 |
| Pension and other postretirement benefits | 2,561 | 1,601 |
| Asset retirement obligations | 3,575 | 3,539 |
| Deferred income taxes | 8,513 | 7,823 |
| Other | 2,218 | 2,178 |
| **Total noncurrent liabilities** | **38,207** | **33,518** |
| **Commitments and Contingencies (Note 14)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 475,913,404 shares outstanding at December 31, 2014 and 456,670,424 shares outstanding at December 31, 2013 | 10,421 | 9,550 |
| Reinvested earnings | 5,316 | 4,742 |
| Accumulated other comprehensive income | 11 | 50 |
| **Total shareholders' equity** | **15,748** | **14,342** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **16,000** | **14,594** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 60,127** | **$ 55,605** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,450 | $ 828 | $ 830 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,433 | 2,077 | 2,272 |
| Allowance for equity funds used during construction | (100) | (101) | (107) |
| Deferred income taxes and tax credits, net | 690 | 1,075 | 648 |
| PSEP disallowed capital expenditures | 116 | 196 | 353 |
| Other | 286 | 355 | 290 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | 13 | (152) | (40) |
| Inventories | (22) | (10) | (24) |
| Accounts payable | (61) | 113 | (4) |
| Income taxes receivable/payable | 376 | (363) | (132) |
| Other current assets and liabilities | 205 | (469) | 262 |
| Regulatory assets, liabilities, and balancing accounts, net | (1,642) | (202) | 291 |
| Other noncurrent assets and liabilities | (67) | 80 | 243 |
| **Net cash provided by operating activities** | **3,677** | **3,427** | **4,882** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (4,833) | (5,207) | (4,624) |
| Decrease in restricted cash | 3 | 29 | 50 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,336 | 1,619 | 1,133 |
| Purchases of nuclear decommissioning trust investments | (1,334) | (1,604) | (1,189) |
| Other | 114 | 56 | 104 |
| **Net cash used in investing activities** | **(4,714)** | **(5,107)** | **(4,526)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings under revolving credit facilities | - | 140 | 120 |
| Repayments under revolving credit facilities | (260) | - | - |
| Net issuances (repayments) of commercial paper, net of discount of $2, $2, and $3 at respective dates | (583) | 542 | (1,021) |
| Proceeds from issuance of short-term debt, net of issuance costs | 300 | - | - |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $17, $18 and $13 at respective dates | 2,308 | 1,532 | 1,137 |
| Short-term debt matured | - | - | (250) |
| Repayments of long-term debt | (889) | (861) | (50) |
| Energy recovery bonds matured | - | - | (423) |
| Common stock issued | 802 | 1,045 | 751 |
| Common stock dividends paid | (828) | (782) | (746) |
| Other | 42 | (41) | 14 |
| **Net cash provided by (used in) financing activities** | **892** | **1,575** | **(468)** |
| **Net change in cash and cash equivalents** | **(145)** | **(105)** | **(112)** |
| **Cash and cash equivalents at January 1** | **296** | **401** | **513** |
| **Cash and cash equivalents at December 31** | **$ 151** | **$ 296** | **$ 401** |

| | | | |
|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (633) | $ (623) | $ (594) |
| Income taxes, net | 501 | (41) | 114 |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Common stock dividends declared but not yet paid | $ 217 | $ 208 | $ 196 |
| Capital expenditures financed through accounts payable | 339 | 322 | 362 |
| Noncash common stock issuances | 21 | 22 | 22 |
| Terminated capital leases | 71 | - | 136 |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Non controlling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2011** | **412,257,082** | **7,602** | **4,712** | **(213)** | **12,101** | **252** | **12,353** |
| Net income | - | - | 830 | - | 830 | - | 830 |
| Other comprehensive income | - | - | - | 112 | 112 | - | 112 |
| Common stock issued, net | 18,461,211 | 773 | - | - | 773 | - | 773 |
| Stock-based compensation amortization | - | 52 | - | - | 52 | - | 52 |
| Common stock dividends declared | - | - | (781) | - | (781) | - | (781) |
| Tax benefit from employee stock plans | - | 1 | - | - | 1 | - | 1 |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2012** | **430,718,293** | **8,428** | **4,747** | **(101)** | **13,074** | **252** | **13,326** |
| Net income | - | - | 828 | - | 828 | - | 828 |
| Other comprehensive income | - | - | - | 151 | 151 | - | 151 |
| Common stock issued, net | 25,952,131 | 1,067 | - | - | 1,067 | - | 1,067 |
| Stock-based compensation amortization | - | 56 | - | - | 56 | - | 56 |
| Common stock dividends declared | - | - | (819) | - | (819) | - | (819) |
| Tax expense from employee stock plans | - | (1) | - | - | (1) | - | (1) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2013** | **456,670,424** | **$ 9,550** | **$ 4,742** | **$ 50** | **$ 14,342** | **$ 252** | **$ 14,594** |
| Net income | - | - | 1,450 | - | 1,450 | - | 1,450 |
| Other comprehensive loss | - | - | - | (39) | (39) | - | (39) |
| Common stock issued, net | 19,242,980 | 823 | - | - | 823 | - | 823 |
| Stock-based compensation amortization | - | 65 | - | - | 65 | - | 65 |
| Common stock dividends declared | - | - | (862) | - | (862) | - | (862) |
| Tax expense from employee stock plans | - | (17) | - | - | (17) | - | (17) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2014** | **475,913,404** | **$ 10,421** | **$ 5,316** | **$ 11** | **$ 15,748** | **$ 252** | **$ 16,000** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| **Operating Revenues** | | | |
| Electric | $ 13,656 | $ 12,489 | $ 12,014 |
| Natural gas | 3,432 | 3,104 | 3,021 |
| **Total operating revenues** | **17,088** | **15,593** | **15,035** |
| **Operating Expenses** | | | |
| Cost of electricity | 5,615 | 5,016 | 4,162 |
| Cost of natural gas | 954 | 968 | 861 |
| Operating and maintenance | 5,635 | 5,742 | 6,045 |
| Depreciation, amortization, and decommissioning | 2,432 | 2,077 | 2,272 |
| **Total operating expenses** | **14,636** | **13,803** | **13,340** |
| **Operating Income** | 2,452 | 1,790 | 1,695 |
| Interest income | 8 | 8 | 6 |
| Interest expense | (720) | (690) | (680) |
| Other income, net | 77 | 84 | 88 |
| **Income Before Income Taxes** | **1,817** | **1,192** | **1,109** |
| Income tax provision | 384 | 326 | 298 |
| **Net Income** | **1,433** | **866** | **811** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 1,419** | **$ 852** | **$ 797** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2014** | **2013** | **2012** |
| **Net Income** | **$ 1,433** | **$ 866** | **$ 811** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $6, $75, and $73, at respective dates) | (8) | 106 | 109 |
| **Total other comprehensive income (loss)** | **(8)** | **106** | **109** |
| **Comprehensive Income** | **$ 1,425** | **$ 972** | **$ 920** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2014** | **2013** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 55 | $ 65 |
| Restricted cash | 298 | 301 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $66 and $80 at December 31, 2014 and 2013, respectively) | 960 | 1,091 |
| Accrued unbilled revenue | 776 | 766 |
| Regulatory balancing accounts | 2,266 | 1,124 |
| Other | 375 | 313 |
| Regulatory assets | 444 | 448 |
| Inventories | | |
| Gas stored underground and fuel oil | 172 | 137 |
| Materials and supplies | 304 | 317 |
| Income taxes receivable | 168 | 563 |
| Other | 409 | 523 |
| **Total current assets** | **6,227** | **5,648** |
| **Property, Plant, and Equipment** | | |
| Electric | 45,162 | 42,881 |
| Gas | 15,678 | 14,379 |
| Construction work in progress | 2,220 | 1,834 |
| **Total property, plant, and equipment** | **63,060** | **59,094** |
| Accumulated depreciation | (19,120) | (17,843) |
| **Net property, plant, and equipment** | **43,940** | **41,251** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 6,322 | 4,913 |
| Nuclear decommissioning trusts | 2,421 | 2,342 |
| Income taxes receivable | 91 | 81 |
| Other | 864 | 814 |
| **Total other noncurrent assets** | **9,698** | **8,150** |
| **TOTAL ASSETS** | **$ 59,865** | **$ 55,049** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, 2014 | 2013 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 633 | $ 914 |
| Long-term debt, classified as current | - | 539 |
| Accounts payable | | |
| Trade creditors | 1,243 | 1,293 |
| Regulatory balancing accounts | 1,090 | 1,008 |
| Other | 444 | 432 |
| Disputed claims and customer refunds | 434 | 154 |
| Interest payable | 195 | 887 |
| Other | 1,604 | 1,382 |
| **Total current liabilities** | **5,643** | **6,609** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 14,700 | 12,717 |
| Regulatory liabilities | 6,290 | 5,660 |
| Pension and other postretirement benefits | 2,477 | 1,530 |
| Asset retirement obligations | 3,575 | 3,539 |
| Deferred income taxes | 8,773 | 8,042 |
| Other | 2,178 | 2,111 |
| **Total noncurrent liabilities** | **37,993** | **33,599** |
| **Commitments and Contingencies (Note 14)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at December 31, 2014 and 2013 | 1,322 | 1,322 |
| Additional paid-in capital | 6,514 | 5,821 |
| Reinvested earnings | 8,130 | 7,427 |
| Accumulated other comprehensive income | 5 | 13 |
| **Total shareholders' equity** | **16,229** | **14,841** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 59,865** | **$ 55,049** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,433 | $ 866 | $ 811 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,432 | 2,077 | 2,272 |
| Allowance for equity funds used during construction | (100) | (101) | (107) |
| Deferred income taxes and tax credits, net | 731 | 1,103 | 684 |
| PSEP disallowed capital expenditures | 116 | 196 | 353 |
| Other | 226 | 299 | 236 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | 16 | (152) | (40) |
| Inventories | (22) | (10) | (24) |
| Accounts payable | (55) | 99 | (26) |
| Income taxes receivable/payable | 395 | (377) | (50) |
| Other current assets and liabilities | 155 | (404) | 272 |
| Regulatory assets, liabilities, and balancing accounts, net | (1,642) | (202) | 291 |
| Other noncurrent assets and liabilities | (66) | 22 | 256 |
| **Net cash provided by operating activities** | **3,619** | **3,416** | **4,928** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (4,833) | (5,207) | (4,624) |
| Decrease in restricted cash | 3 | 29 | 50 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,336 | 1,619 | 1,133 |
| Purchases of nuclear decommissioning trust investments | (1,334) | (1,604) | (1,189) |
| Other | 29 | 21 | 16 |
| **Net cash used in investing activities** | **(4,799)** | **(5,142)** | **(4,614)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $2, $2, and $3 at respective dates | (583) | 542 | (1,021) |
| Proceeds from issuance of short-term debt, net of issuance costs | 300 | - | - |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $14, $18, and $13 at respective dates | 1,961 | 1,532 | 1,137 |
| Short-term debt matured | - | - | (250) |
| Long-term debt matured or repurchased | (539) | (861) | (50) |
| Energy recovery bonds matured | - | - | (423) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution from PG&E Corporation | 705 | 1,140 | 885 |
| Other | 56 | (26) | 28 |
| **Net cash provided by (used in) financing activities** | **1,170** | **1,597** | **(424)** |
| **Net change in cash and cash equivalents** | **(10)** | **(129)** | **(110)** |
| **Cash and cash equivalents at January 1** | **65** | **194** | **304** |
| **Cash and cash equivalents at December 31** | **$ 55** | **$ 65** | **$ 194** |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (618) | $ (600) | $ (574) |
| Income taxes, net | 500 | (62) | 174 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Capital expenditures financed through accounts payable | $ | 339 | $ | 322 | $ | 362 |
| Terminated capital leases | | 71 | | - | | 136 |

See accompanying Notes to the Consolidated Financial Statements.

## Pacific Gas and Electric Company
## CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
## (in millions)

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2011** | **$ 258** | **$ 1,322** | **$ 3,796** | **$ 7,210** | **$ (202)** | **$ 12,384** |
| Net income | - | - | - | 811 | - | 811 |
| Other comprehensive income | - | - | - | - | 109 | 109 |
| Equity contribution | - | - | 885 | - | - | 885 |
| Tax benefit from employee stock plans | - | - | 1 | - | - | 1 |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2012** | **258** | **1,322** | **4,682** | **7,291** | **(93)** | **13,460** |
| Net income | - | - | - | 866 | - | 866 |
| Other comprehensive income | - | - | - | - | 106 | 106 |
| Equity contribution | - | - | 1,140 | - | - | 1,140 |
| Tax expense from employee stock plans | - | - | (1) | - | - | (1) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2013** | **258** | **1,322** | **5,821** | **7,427** | **13** | **14,841** |
| Net income | - | - | - | 1,433 | - | 1,433 |
| Other comprehensive loss | - | - | - | - | (8) | (8) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (12) | - | - | (12) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2014** | **$ 258** | **$ 1,322** | **$ 6,514** | **$ 8,130** | **$ 5** | **$ 16,229** |

See accompanying Notes to the Consolidated Financial Statements.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's consolidated financial statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's consolidated financial statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility operate in one segment.

The consolidated financial statements have been prepared in accordance with GAAP and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the consolidated financial statements are appropriate and reasonable. Actual results could differ materially from those estimates.

### NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### Regulation and Regulated Operations

As a regulated entity, the Utility collects rates from customers to recover "revenue requirements" that have been authorized by the CPUC or the FERC based on the Utility's costs of service. The Utility's ability to recover a significant portion of its authorized revenue requirements through rates is generally independent, or "decoupled," from the volume of the Utility's electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

The Utility also records a regulatory balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund. In addition, the Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. These differences have no impact on net income. See "Revenue Recognition" below.

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable. To the extent that portions of the Utility's operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

**Revenue Recognition**

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three years. In general, the Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, revenue is recognized ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled.

**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

**Restricted Cash**

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See Note 12 below.)

**Allowance for Doubtful Accounts Receivable**

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectable customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

**Inventories**

Inventories are carried at weighted-average cost and include natural gas stored underground as well as materials and supplies. Natural gas stored underground represents gas that is recorded to inventory when injected and then expensed as the gas is withdrawn for distribution to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and then expensed or capitalized to plant, as appropriate, when consumed or installed.

The Utility also purchases GHG emission allowances that are recorded as inventory. They are carried at weighted-average cost and included in current assets – other and other noncurrent assets – other on the Consolidated Balance Sheets. The costs of the GHG emissions are expensed and recoverable through rates.

**Property, Plant, and Equipment**

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value. Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

| (in millions, except estimated useful lives) | Estimated Useful Lives (years) | Balance at December 31, 2014 | 2013 |
|---|---|---|---|
| Electricity generating facilities [1] | 10 to 100 | $ 9,374 | $ 9,116 |
| Electricity distribution facilities | 10 to 55 | 26,633 | 25,333 |
| Electricity transmission facilities | 10 to 70 | 9,155 | 8,429 |
| Natural gas distribution facilities | 20 to 60 | 9,741 | 9,117 |
| Natural gas transportation and storage facilities | 7 to 65 | 5,937 | 5,265 |
| Construction work in progress | | 2,220 | 1,834 |
| **Total property, plant, and equipment** | | **63,060** | **59,094** |
| Accumulated depreciation | | (19,120) | (17,843) |
| **Net property, plant, and equipment** | | $ **43,940** | $ **41,251** |

[1] Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 14 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.77% in 2014, 3.51% in 2013, and 3.63% in 2012. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $45 million and $100 million during 2014, $47 million and $101 million during 2013, and $49 million and $107 million during 2012.

**Asset Retirement Obligations**

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment.

The Utility adjusts its nuclear decommissioning obligation to reflect changes in the estimated costs of decommissioning its nuclear power facilities and records this as an adjustment to the ARO liability on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $2.5 billion at December 31, 2014 and 2013. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $3.5 billion at December 31, 2014 and 2013 (or $6.1 billion in future dollars). These estimates are based on the 2012 decommissioning cost studies, prepared in accordance with CPUC requirements.

The following table summarizes the changes in ARO liability during 2014 and 2013:

| (in millions) | 2014 | 2013 |
|---|---|---|
| ARO liability at beginning of year | $ 3,538 | $ 2,919 |
| Revision in estimated cash flows | (16) | 596 |
| Accretion | 163 | 130 |
| Liabilities settled | (110) | (107) |
| **ARO liability at end of year** | **$ 3,575** | **$ 3,538** |

The Utility has not recorded a liability related to certain ARO's for assets that are expected to operate in perpetuity. As the Utility cannot estimate a settlement date or range of potential settlement dates for these assets, reasonable estimates of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities associated with substations and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration or land to the conditions under certain agreements.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. The Utility recorded charges of $116 million, $196 million and $353 million in 2014, 2013, and 2012, respectively, for PSEP capital costs that are expected to exceed the CPUC's authorized levels or that are specifically disallowed. (See "Enforcement and Litigation Matters" in Note 14 below).

**Nuclear Decommissioning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

**Gains and Losses on Debt Extinguishments**

Deferred gains and losses on debt extinguishments are recorded to regulatory assets in current assets and regulatory assets in other noncurrent assets on the Consolidated Balance Sheets. Gains and losses on debt extinguishments associated with regulated operations are deferred and amortized over a period consistent with the recovery of costs through regulated rates. PG&E Corporation and the Utility recorded unamortized loss on debt extinguishments, net of gain, of $135 million, $157 million, and $163 million at December 31, 2014, 2013, and 2012, respectively. The amortization expense related to this loss was $22 million in 2014 and $23 million in both 2013 and 2012.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2014, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2014, it did not consolidate any of them.

PG&E Corporation affiliates previously entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that were considered VIEs. Since PG&E Corporation was not the primary beneficiary of any of these VIEs, they were not consolidated. On July 2, 2014, PG&E Corporation disposed of its interest in the tax equity agreements and has no remaining commitment to fund these agreements.

**Other Accounting Policies**

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies" in Note 14 of the Notes to the Consolidated Financial Statements.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2014 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| Beginning balance | $ (7) | 15 | 42 | 50 |
| **Other comprehensive income before reclassifications:** | | | | |
| Change in investments (net of taxes of $0, $0, and $4, respectively) | - | - | 5 | 5 |
| Unrecognized net actuarial loss (net of taxes of $404, $19, and $0, respectively) | (588) | (28) | - | (616) |
| Unrecognized prior service cost (net of taxes of $0, $0, and $0, respectively) | 1 | - | - | 1 |
| Transfer to regulatory account (net of taxes of $394, $19, and $0, respectively) | 573 | 28 | - | 601 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $8, $9, and $0, respectively) [1] | 12 | 14 | - | 26 |
| Amortization of net actuarial loss (net of taxes of $1, $1, and $0, respectively) [1] | 1 | 1 | - | 2 |
| Transfer to regulatory account (net of taxes of $9, $10, and $0, respectively) [1] | (13) | (15) | - | (28) |
| Realized gain on investments (net of taxes of $0, $0, and $20, respectively) | - | - | (30) | (30) |
| **Net current period other comprehensive loss** | **(14)** | **-** | **(25)** | **(39)** |
| **Ending balance** | **$ (21)** | **15** | **17** | **11** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2013 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| Beginning balance | $ (28) | (77) | 4 | (101) |
| **Other comprehensive income before reclassifications:** | | | | |
| Change in investments (net of taxes of $0, $0, and $26, respectively) | - | - | 38 | 38 |
| Unrecognized net actuarial loss (net of taxes of $804, $35, and $0, respectively) | 1,169 | 45 | - | 1,214 |
| Transfer to regulatory account (net of taxes of $790, $22, and $0, respectively) | (1,150) | 31 | - | (1,119) |
| **Amounts reclassified from other comprehensive income:** [1] | | | | |
| Amortization of prior service cost (net of taxes of $8, $10, and $0, respectively) | 12 | 13 | - | 25 |
| Amortization of net actuarial loss (net of taxes of $45, $3, and $0, respectively) | 66 | 3 | - | 69 |
| Transfer to regulatory account (net of taxes of $54, $0, and $0, respectively) | (76) | - | - | (76) |
| **Net current period other comprehensive income** | **21** | **92** | **38** | **151** |
| **Ending balance** | **$ (7)** | **15** | **42** | **50** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**New Accounting Pronouncements**

***Revenue Recognition Standard***

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers,* which amends existing revenue recognition guidance. The accounting standards update will be effective on January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

## NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

**Regulatory Assets**

Long-term regulatory assets are comprised of the following:

| | Balance at December 31, | | Recovery |
|---|---|---|---|
| **(in millions)** | **2014** | **2013** | **Period** |
| Pension benefits [1] | $ 2,347 | $ 1,444 | N/A [4] |
| Deferred income taxes [1] | 2,390 | 1,835 | 47 years |
| Utility retained generation [2] | 456 | 503 | 11 years |
| Environmental compliance costs [1] | 717 | 628 | 32 years |
| Price risk management [1] | 127 | 106 | 10 years |
| Electromechanical meters [3] | 70 | 135 | 2 years |
| Unamortized loss, net of gain, on reacquired debt [1] | 113 | 135 | 12 years |
| Other | 102 | 127 | Various |
| **Total long-term regulatory assets** | **$ 6,322** | **$ 4,913** | |

[1] Represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. Pension benefits also includes amounts that otherwise would be recorded to accumulated other comprehensive income/loss in the Consolidated Balance Sheets. (See Note 11 below.)
[2] In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.
[3] Represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices.
[4] The Utility expects to continuously recover pension benefits.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, regulatory assets for electromechanical meters, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

### Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Balance at December 31, 2014 | | Balance at December 31, 2013 | |
|---|---|---|---|---|
| Cost of removal obligations [1] | $ | 4,211 | $ | 3,844 |
| Recoveries in excess of AROs [2] | | 754 | | 748 |
| Public purpose programs [3] | | 701 | | 587 |
| Other | | 624 | | 481 |
| **Total long-term regulatory liabilities** | **$** | **6,290** | **$** | **5,660** |

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.
(2) Represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the Utility's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments. (See Note 10 below.)
(3) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

### Regulatory Balancing Accounts

The Utility's recovery of revenue requirements and costs is generally decoupled from the volume of sales. The Utility tracks (1) differences between the Utility's authorized revenue requirement and actual customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets.

The Utility sells and delivers electricity and natural gas. The Utility also administers public purpose programs, primarily related to customer energy efficiency programs. The balancing accounts associated with these items will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

| | Receivable | | | |
|---|---|---|---|---|
| | Balance at December 31, | | | |
| (in millions) | 2014 | | 2013 | |
| Electric distribution | $ | 344 | $ | 102 |
| Utility generation | | 261 | | 57 |
| Gas distribution | | 566 | | 70 |
| Energy procurement | | 608 | | 410 |
| Public purpose programs | | 109 | | 56 |
| Other | | 378 | | 429 |
| **Total regulatory balancing accounts receivable** | **$** | **2,266** | **$** | **1,124** |

| (in millions) | Payable Balance at December 31, 2014 | | 2013 | |
|---|---|---|---|---|
| Energy procurement | $ | 188 | $ | 298 |
| Public purpose programs | | 154 | | 171 |
| Other [1] | | 748 | | 539 |
| **Total regulatory balancing accounts payable** | **$** | **1,090** | **$** | **1,008** |

[1] At December 31, 2014, Other regulatory balancing accounts payable mostly includes energy supplier settlements. (See Note 12 for additional details.)

## NOTE 4: DEBT

### Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

| | December 31, | |
|---|---|---|
| **(in millions)** | **2014** | **2013** |
| **PG&E Corporation** | | |
| Senior notes, 5.75%, due 2014 | - | 350 |
| Senior notes, 2.40%, due 2019 | 350 | - |
| Less: current portion | - | (350) |
| **Total senior notes** | **350** | **-** |
| **Total PG&E Corporation long-term debt** | **350** | **-** |
| **Utility** | | |
| Senior notes: | | |
| 4.80% due 2014 | - | 539 |
| 5.625% due 2017 | 700 | 700 |
| 8.25% due 2018 | 800 | 800 |
| 3.50% due 2020 | 800 | 800 |
| 4.25% due 2021 | 300 | 300 |
| 3.25% due 2021 | 250 | 250 |
| 2.45% due 2022 | 400 | 400 |
| 3.25% due 2023 | 375 | 375 |
| 3.85% due 2023 | 300 | 300 |
| 3.40% due 2024 | 350 | - |
| 3.75% due 2024 | 450 | - |
| 6.05% due 2034 | 3,000 | 3,000 |
| 5.80% due 2037 | 950 | 950 |
| 6.35% due 2038 | 400 | 400 |
| 6.25% due 2039 | 550 | 550 |
| 5.40% due 2040 | 800 | 800 |
| 4.50% due 2041 | 250 | 250 |
| 4.45% due 2042 | 400 | 400 |
| 3.75% due 2042 | 350 | 350 |
| 4.60% due 2043 | 375 | 375 |
| 5.125% due 2043 | 500 | 500 |
| 4.75% due 2044 | 675 | - |
| 4.30% due 2045 | 500 | - |
| Less: current portion | - | (539) |
| Unamortized discount, net of premium | (43) | (51) |
| **Total senior notes, net of current portion** | **13,432** | **11,449** |
| Pollution control bonds: | | |
| Series 1996 C, E, F, 1997 B, variable rates (1), due 2026 (2) | 614 | 614 |
| Series 2004 A-D, 4.75%, due 2023 (3) | 345 | 345 |
| Series 2009 A-D, variable rates (1), due 2016 and 2026 (4) | 309 | 309 |
| **Total pollution control bonds** | **1,268** | **1,268** |
| **Total Utility long-term debt, net of current portion** | **14,700** | **12,717** |
| **Total consolidated long-term debt, net of current portion** | **$ 15,050** | **$ 12,717** |

(1) At December 31, 2014, interest rates on these bonds and the related loans ranged from 0.01% to 0.02%.

(2) Each series of these bonds is supported by a separate letter of credit. In April 2014, the letters of credit were extended to April 1, 2019. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(3) The Utility has obtained credit support from an insurance company for these bonds.

[(4)] Each series of these bonds is supported by a separate direct-pay letter of credit. In June 2014, Series A and B letters of credit were extended to June 5, 2019. Series C and D letters expire on December 3, 2016 to coincide with the maturity of the underlying bonds. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at December 31, 2014:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2019 | $ 300 [(1)] | $ - | $ - | $ 300 |
| Utility | April 2019 | 3,000 [(2)] | 84 | 333 | 2,583 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 84** | **$ 333** | **$ 2,883** |

[(1)] Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
[(2)] Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

For 2014, the average outstanding bank borrowings on PG&E Corporation's revolving credit facility was $27 million and the maximum outstanding balance during the year was $260 million. In February 2014, PG&E Corporation repaid the full outstanding bank borrowings of $260 million and initiated borrowing under its commercial paper program established in January 2014. For the year ended December 31, 2014, PG&E Corporation's average outstanding commercial paper balance was $118 million and the maximum outstanding balance during the period was $260 million. For 2014, the Utility's average outstanding commercial paper balance was $609 million and the maximum outstanding balance during the year was $1.4 billion. The Utility did not have any bank borrowings in 2014.

***Revolving Credit Facilities***

In April 2014, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from April 1, 2018 to April 1, 2019. These agreements contain substantially similar terms as the original 2011 credit agreements. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for additional periods. Provided certain conditions are met, PG&E Corporation and the Utility have the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the revolving credit facilities by up to $100 million and $500 million, respectively, in the aggregate for all such increases.

Borrowings under the revolving credit facilities (other than swingline loans) bear interest based, at PG&E Corporation's and the Utility's election, on (1) a London Interbank Offered Rate plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the federal funds rate, or the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. PG&E Corporation and the Utility also will pay a facility fee on the total commitments of the lenders under the revolving credit facilities. The applicable margins and the facility fees will be based on PG&E Corporation's and the Utility's senior unsecured debt ratings issued by Standard & Poor's Rating Services and Moody's Investor Service. Facility fees are payable quarterly in arrears.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility.

***Commercial Paper Programs***

For 2014, the average yield on outstanding PG&E Corporation and Utility commercial paper was 0.24% and 0.23%, respectively.

The borrowings from PG&E Corporation and the Utility's commercial paper programs are used primarily to fund temporary financing needs. Liquidity support for these borrowings is provided by available capacity under their respective revolving credit facilities, as described above. PG&E Corporation and the Utility treat the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation's and the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

***Other Short-term Borrowings***

In May 2014, the Utility issued $300 million principal amount of Floating Rate Senior Notes due May 11, 2015.

## Repayment Schedule

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2014 are reflected in the table below:

| **(in millions, except interest rates)** | **2015** | **2016** | **2017** | **2018** | **2019** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest rate | - | - | - | - | 2.40 % | - | 2.40 % |
| Fixed rate obligations | $ - | $ - | $ - | $ - | $ 350 | $ - | $ 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | - | - | 5.63 % | 8.25 % | - | 4.92 % | 5.15 % |
| Fixed rate obligations | $ - | $ - | $ 700 | $ 800 | $ - | $ 12,320 | $ 13,820 |
| Variable interest rate as of December 31, 2014 | - | 0.01 % | - | - | 0.01 % | - | 0.01 % |
| Variable rate obligations [(1)] | $ - | $ 160 | $ - | $ - | $ 763 | $ - | $ 923 |
| **Total consolidated debt** | **$ -** | **$ 160** | **$ 700** | **$ 800** | **$ 1,113** | **$ 12,320** | **$ 15,093** |

[(1)] These bonds, due in 2016 and 2026, are backed by separate letters of credit that expire on December 3, 2016, April 1, 2019, or June 5, 2019.

**NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION**

PG&E Corporation had 475,913,404 shares of common stock outstanding at December 31, 2014. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2014.

In February 2014, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $500 million. During 2014, PG&E Corporation sold 11 million shares under the February 2014 equity distribution agreement for cash proceeds of $496 million, exhausting the capacity under this agreement. This amount is net of commissions paid of $4 million.

In addition, PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During 2014, 8 million shares were issued for cash proceeds of $306 million under these plans.

**Dividends**

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. For 2014, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of $0.455 per share.

Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on a weighted average over four years. PG&E Corporation and the Utility are in compliance with these restrictions. At December 31, 2014, the Utility had restricted net assets of $14.6 billion and was limited to $153 million of additional common stock dividends it could pay to PG&E Corporation at December 31, 2014.

**Long-Term Incentive Plan**

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. In May 2014, the 2006 LTIP was terminated and the 2014 LTIP became effective. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 16,184,126 shares were available for future awards at December 31, 2014.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2014, 2013, and 2012:

| **(in millions)** | **2014** | **2013** | **2012** |
|---|---|---|---|
| Restricted stock units | $ 42 | $ 36 | $ 31 |
| Performance shares | 36 | 28 | 26 |
| Total compensation expense (pre-tax) | **$ 78** | **$ 64** | **$ 57** |
| Total compensation expense (after-tax) | **$ 47** | **$ 38** | **$ 34** |

The amount of share-based compensation costs capitalized during 2014, 2013, and 2012 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

Prior to 2014, restricted stock units generally vested over four years in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Restricted stock units granted in 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2014, 2013, and 2012 was $43.76, $42.92, and $42.17, respectively. The total fair value of restricted stock units that vested during 2014, 2013, and 2012 was $34 million, $30 million, and $18 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. As of December 31, 2014, $51 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.77 years.

The following table summarizes restricted stock unit activity for 2014:

| | Number of Restricted Stock Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 2,300,021 | $ 43.16 |
| Granted | 1,092,035 | $ 43.76 |
| Vested | (777,883) | $ 43.28 |
| Forfeited | (75,816) | $ 43.01 |
| Nonvested at December 31 | **2,538,357** | $ 43.38 |

***Performance Shares***

Performance shares generally will vest three years after the grant date. Upon vesting, performance shares are settled in shares of common stock based on PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period. Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled.

Compensation expense attributable to performance share is generally recognized rateably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model. The weighted average grant-date fair value for performance shares granted during 2014, 2013, and 2012 was $51.81, $33.45, and $41.93 respectively. There was no tax benefit associated with performance shares during each of these periods. As of December 31, 2014, $34 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.18 years.

The following table summarizes activity for performance shares in 2014:

| | Number of Performance Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,791,320 | $ 37.85 |
| Granted | 843,185 | 51.81 |
| Vested | (275,247) | 41.94 |
| Forfeited [1] | (665,319) | 42.34 |
| Nonvested at December 31 | **1,693,939** | $ 42.37 |

[1] Includes performance shares that expired with zero value as performance targets were not met.

**NOTE 6: PREFERRED STOCK**

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. At December 31, 2014 and December 31, 2013, the Utility's preferred stock outstanding included $145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $113 million of shares with interest rates between 4.36% and 5% that are redeemable between $25.75 and $27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

At December 31, 2014, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2014, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid $14 million of dividends on preferred stock in each of 2014, 2013, and 2012.

**NOTE 7: EARNINGS PER SHARE**

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2014, 2013, and 2012.

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2014** | **2013** | **2012** |
| **Income available for common shareholders** | $ 1,436 | $ 814 | $ 816 |
| **Weighted average common shares outstanding, basic** | 468 | 444 | 424 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | 2 | 1 | 1 |
| **Weighted average common share outstanding, diluted** | 470 | 445 | 425 |
| **Total earnings per common share, diluted** | **$ 3.06** | **$ 1.83** | **$ 1.92** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

**NOTE 8: INCOME TAXES**

PG&E Corporation and the Utility use the liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| **(in millions)** | **2014** | **2013** | **2012** | **2014** | **2013** | **2012** |
| Current: | | | | | | |
| Federal | $ (84) | $ (218) | $ (74) | $ (84) | $ (222) | $ (52) |
| State | (41) | (26) | 33 | (29) | (23) | 41 |
| Deferred: | | | | | | |
| Federal | 396 | 552 | 374 | 426 | 604 | 404 |
| State | 78 | (35) | (92) | 75 | (28) | (91) |
| Tax credits | (4) | (5) | (4) | (4) | (5) | (4) |
| **Income tax provision** | **$ 345** | **$ 268** | **$ 237** | **$ 384** | **$ 326** | **$ 298** |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| **(in millions)** | **2014** | **2013** | **2014** | **2013** |
| **Deferred income tax assets:** | | | | |
| Customer advances for construction | $ 88 | $ 90 | $ 88 | $ 90 |
| Reserve for damages | 137 | 161 | 137 | 161 |
| Environmental reserve | 111 | 152 | 111 | 152 |
| Compensation | 107 | 167 | 36 | 102 |
| Net operating loss carryforward | 1,177 | 890 | 946 | 670 |
| GHG allowances | 56 | 108 | 56 | 108 |
| Other | 74 | 135 | 100 | 128 |
| **Total deferred income tax assets** | **$ 1,750** | **$ 1,703** | **$ 1,474** | **$ 1,411** |

| | | | | |
|---|---|---|---|---|
| **Deferred income tax liabilities:** | | | | |
| Regulatory balancing accounts | $ 512 | $ 261 | $ 512 | $ 261 |
| Property related basis differences | 8,683 | 8,048 | 8,666 | 8,038 |
| Income tax regulatory asset [(1)] | 974 | 748 | 974 | 748 |
| Other | 88 | 151 | 86 | 86 |
| **Total deferred income tax liabilities** | **$ 10,257** | **$ 9,208** | **$ 10,238** | **$ 9,133** |
| **Total net deferred income tax liabilities** | **$ 8,507** | **$ 7,505** | **$ 8,764** | **$ 7,722** |
| **Classification of net deferred income tax liabilities:** | | | | |
| Included in current liabilities (assets) | $ (6) | $ (318) | $ (9) | $ (320) |
| Included in noncurrent liabilities | 8,513 | 7,823 | 8,773 | 8,042 |
| **Total net deferred income tax liabilities** | **$ 8,507** | **$ 7,505** | **$ 8,764** | **$ 7,722** |

(1) Represents the deferred income tax component of the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. (See Note 3 above.)

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

| | **PG&E Corporation** | | | **Utility** | | |
|---|---|---|---|---|---|---|
| | **Year Ended December 31,** | | | | | |
| | **2014** | **2013** | **2012** | **2014** | **2013** | **2012** |
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) [(1)] | 1.4 | (3.1) | (3.9) | 1.6 | (2.2) | (3.0) |
| Effect of regulatory treatment of fixed asset differences [(2)] | (15.0) | (4.2) | (4.1) | (14.7) | (3.8) | (3.9) |
| Tax credits | (0.7) | (0.4) | (0.6) | (0.7) | (0.4) | (0.6) |
| Benefit of loss carryback | (0.8) | (1.1) | (0.7) | (0.8) | (1.0) | (0.4) |
| Non deductible penalties | 0.3 | 0.8 | 0.6 | 0.3 | 0.7 | 0.5 |
| Other, net | (0.8) | (2.2) | (3.8) | 0.4 | (0.9) | (0.8) |
| **Effective tax rate** | **19.4 %** | **24.8 %** | **22.5 %** | **21.1 %** | **27.4 %** | **26.8 %** |

(1) Includes the effect of state flow-through ratemaking treatment.
(2) Represents effect of federal flow-through ratemaking treatment including those deductions related to repairs and certain other property-related costs discussed below in the "2014 GRC Impact" section.

***Unrecognized tax benefits***

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| **(in millions)** | | | | | | |
| **Balance at beginning of year** | $ 666 | $ 581 | $ 506 | $ 660 | $ 575 | $ 503 |
| Additions for tax position taken during a prior year | 7 | 12 | 32 | 7 | 12 | 26 |
| Reductions for tax position taken during a prior year | (9) | (6) | (13) | (9) | (6) | (10) |
| Additions for tax position taken during the current year | 61 | 79 | 67 | 61 | 79 | 67 |
| Settlements | (12) | - | (11) | (12) | - | (11) |
| **Balance at end of year** | **$ 713** | **$ 666** | **$ 581** | **$ 707** | **$ 660** | **$ 575** |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2014 for PG&E Corporation and the Utility was $20 million, with the remaining balance representing the potential deferral of taxes to later years.

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the IRS guidance that is issued and the resolution of the audits related to the 2011, 2012, and 2013 tax returns (see "2014 GRC impact" below). As of December 31, 2014, it is reasonably possible that unrecognized tax benefits will decrease by approximately $330 million within the next 12 months, and most of this decrease would not impact net income.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2014, 2013, and 2012, these amounts were immaterial.

***2014 GRC impact***

The 2014 GRC decision authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets or liabilities. Therefore, PG&E Corporation's and the Utility's effective income tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In addition, recent guidance from the IRS allowed the Utility to deduct more repair costs than previously forecasted in the GRC. For the year ended December 31, 2014, the Utility recognized a reduction in income tax expense of $235 million consistent with a lower revenue requirement in the 2014 GRC and IRS guidance.

***IRS settlements and years that remain subject to examination***

PG&E Corporation participates in the Compliance Assurance Process, a real-time IRS audit intended to expedite resolution of tax matters. The Compliance Assurance Process audit culminates with a letter from the IRS indicating its acceptance of the return.

The IRS is currently reviewing several matters in the 2011, 2012, and 2013 tax returns. The most significant relates to a 2011 accounting method change to adopt guidance issued by the IRS in determining which repair costs are deductible for the electric transmission and distribution businesses. PG&E Corporation and the Utility expect that the IRS will complete the review of the deductible repair costs for the electric transmission and distribution businesses in 2015. The IRS is also expected to issue guidance during 2015 that determines which repair costs are deductible for the natural gas transmission and distribution businesses.

The Tax Increase Prevention Act, signed into law on December 19, 2014, extended 50% bonus federal tax depreciation on qualified property placed into service in 2014.

***Carryforwards***

As of December 31, 2014, PG&E Corporation had approximately $4.1 billion of federal net operating loss carryforwards and $77 million of tax credit carryforwards, which will expire between 2029 and 2034. In addition, PG&E Corporation had approximately $219 million of loss carryforwards related to charitable contributions, which will expire between 2015 and 2019. PG&E Corporation had $123 million of California net operating loss carryforwards which will expire between 2033 and 2034 and $30 million of California credit carryforwards, some of which will expire in 2024 and others which will carryforward indefinitely. PG&E Corporation believes it is more likely than not the tax benefits associated with the federal net operating loss, charitable contributions, and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2014. As of December 31, 2014, PG&E Corporation had approximately $24 million of federal net operating loss carryforwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

## NOTE 9: DERIVATIVES

### Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include forward contracts, swaps, futures, options, and CRRs.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. As long as the current ratemaking mechanism discussed in Note 2, above, remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives, the Utility expects to recover fully, in rates, all costs related to derivatives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

Cash collateral paid or received is offset against the fair value of derivative instruments executed with the same counterparty under a master netting arrangement, where the right of offset and the intention to offset exist. Derivatives are presented in the Utility's Consolidated Balance Sheets on a net basis; see below.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. The fair value of these items is not reflected in the Consolidated Balance Sheets at fair value, eligible derivatives are accounted for under the accrual method of accounting.

**Volume of Derivative Activity**

At December 31, 2014 and 2013, respectively, the volumes of the Utility's outstanding derivatives were as follows:

| Underlying Product | Instruments | Contract Volume 2014 | Contract Volume 2013 |
|---|---|---|---|
| Natural Gas [1] (MMBtus [2]) | Forwards and Swaps | 308,130,101 | 331,840,788 |
| | Options | 164,418,002 | 260,262,916 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 5,346,787 | 8,089,269 |
| | Congestion Revenue Rights [3] | 224,124,341 | 250,922,591 |

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in congestion costs based on demand when there is insufficient transmission capacity.

**Presentation of Derivative Instruments in the Financial Statements**

At December 31, 2014, the Utility's outstanding derivative balances were as follows:

| (in millions) | Commodity Risk Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
|---|---|---|---|---|
| Current assets – other | $ 73 | $ (4) | $ 19 | $ 88 |
| Other noncurrent assets – other | 178 | (13) | - | 165 |
| Current liabilities – other | (78) | 4 | 26 | (48) |
| Noncurrent liabilities – other | (140) | 13 | 9 | (118) |
| **Total commodity risk** | **$ 33** | **$ -** | **$ 54** | **$ 87** |

At December 31, 2013, the Utility's outstanding derivative balances were as follows:

| (in millions) | Commodity Risk Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
|---|---|---|---|---|
| Current assets – other | $ 42 | $ (10) | $ 16 | $ 48 |
| Other noncurrent assets – other | 99 | (4) | - | 95 |
| Current liabilities – other | (122) | 10 | 69 | (43) |
| Noncurrent liabilities – other | (110) | 4 | 2 | (104) |
| **Total commodity risk** | **$ (91)** | **$ -** | **$ 87** | **$ (4)** |

Gains and losses recorded on the Utility's derivatives were as follows:

| (in millions) | Commodity Risk For the year ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Unrealized gain/(loss) - regulatory assets and liabilities [1] | $ 124 | $ 238 | $ 391 |
| Realized loss - cost of electricity [2] | (83) | (178) | (486) |
| Realized loss - cost of natural gas [2] | (8) | (22) | (38) |
| **Total commodity risk** | **$ 33** | **$ 38** | **$ (133)** |

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
[2] These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2014, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2014** | **2013** |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (47) | $ (79) |
| Related derivatives in an asset position | - | 4 |
| Collateral posting in the normal course of business related to these derivatives | 44 | 65 |
| **Net position of derivative contracts/additional collateral posting requirements** [1] | **$ (3)** | **$ (10)** |

[1] This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

**NOTE 10: FAIR VALUE MEASUREMENTS**

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts and other investments are held by PG&E Corporation and not the Utility):

| (in millions) | Fair Value Measurements At December 31, 2014 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Money market investments | $ 94 | $ - | $ - | $ - | **$ 94** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 17 | - | - | - | **17** |
| Global equity securities | 1,585 | 13 | - | - | **1,598** |
| Fixed-income securities | 741 | 389 | - | - | **1,130** |
| Total nuclear decommissioning trusts [2] | **2,343** | **402** | **-** | **-** | **2,745** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | - | 17 | 232 | 2 | **251** |
| Gas | 1 | 1 | - | - | **2** |
| Total price risk management instruments | **1** | **18** | **232** | **2** | **253** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 42 | - | - | **42** |
| Life insurance contracts | - | 72 | - | - | **72** |
| Total rabbi trusts | **-** | **114** | **-** | **-** | **114** |
| Long-term disability trust | | | | | |
| Money market investments | 7 | - | - | - | **7** |
| Global equity securities | - | 25 | - | - | **25** |
| Fixed-income securities | - | 128 | - | - | **128** |
| Total long-term disability trust | **7** | **153** | **-** | **-** | **160** |
| Other investments | 33 | - | - | - | **33** |
| **Total assets** | **$ 2,478** | **$ 687** | **$ 232** | **$ 2** | **$ 3,399** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 47 | $ 5 | $ 163 | $ (52) | **$ 163** |
| Gas | - | 3 | - | - | **3** |
| **Total liabilities** | **$ 47** | **$ 8** | **$ 163** | **$ (52)** | **$ 166** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $324 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2013 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Money market investments | $ 226 | $ - | $ - | $ - | $ **226** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 38 | - | - | - | **38** |
| U.S. equity securities | 1,046 | 11 | | - | **1,057** |
| Non-U.S. equity securities | 457 | - | - | - | **457** |
| U.S. government and agency securities | 760 | 156 | - | - | **916** |
| Municipal securities | - | 25 | - | - | **25** |
| Other fixed-income securities | - | 162 | - | - | **162** |
| Total nuclear decommissioning trusts [2] | **2,301** | **354** | **-** | **-** | **2,655** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 2 | 27 | 107 | 3 | **139** |
| Gas | - | 5 | - | (1) | **4** |
| Total price risk management instruments | **2** | **32** | **107** | **2** | **143** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 39 | - | - | **39** |
| Life insurance contracts | - | 70 | - | - | **70** |
| Total rabbi trusts | **-** | **109** | **-** | **-** | **109** |
| Long-term disability trust | | | | | |
| Money market investments | 9 | - | - | - | **9** |
| U.S. equity securities | - | 14 | - | - | **14** |
| Non-U.S. equity securities | - | 12 | - | - | **12** |
| Fixed-income securities | - | 122 | - | - | **122** |
| Total long-term disability trust | **9** | **148** | **-** | **-** | **157** |
| Other investments | 84 | - | - | - | **84** |
| **Total assets** | **$ 2,622** | **$ 643** | **$ 107** | **$ 2** | **$ 3,374** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 19 | $ 72 | $ 137 | $ (84) | $ **144** |
| Gas | 1 | 3 | - | (1) | **3** |
| **Total liabilities** | **$ 20** | **$ 75** | **$ 137** | **$ (85)** | **$ 147** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $313 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. Investments, primarily consisting of equity securities, that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the year ended December 31, 2014 and 2013.

***Trust Assets***

Nuclear decommissioning trust assets and other trust assets are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1. Equity securities also include commingled funds that are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world. Investments in these funds are classified as Level 2 because price quotes are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are classified as Level 3 and are valued based on CRR auction prices, including historical prices. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Risk Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

| (in millions) | Fair Value at December 31, 2014 | | | | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Valuation Technique** | **Unobservable Input** | **Range [1]** |
| Congestion revenue rights | $ 232 | $ 63 | Market approach | CRR auction prices | $ (15.97) - 8.17 |
| Power purchase agreements | $ - | $ 100 | Discounted cash flow | Forward prices | $ 16.04 - 56.21 |

[1] Represents price per megawatt-hour

| (in millions) | Fair Value at December 31, 2013 | | | | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Valuation Technique** | **Unobservable Input** | **Range [1]** |
| Congestion revenue rights | $ 107 | $ 32 | Market approach | CRR auction prices | $ (6.47) - 12.04 |
| Power purchase agreements | $ - | $ 105 | Discounted cash flow | Forward prices | $ 23.43 - 51.75 |

[1] Represents price per megawatt-hour

**Level 3 Reconciliation**

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2014 and 2013, respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2014** | **2013** |
| Liability balance as of January 1 | **$ (30)** | **$ (79)** |
| Realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | 99 | 49 |
| **Asset (liability) balance as of December 31** | **$ 69** | **$ (30)** |

[1] The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2014 and 2013, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2014 and 2013.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2014 | | 2013 | |
| **(in millions)** | **Carrying Amount** | **Level 2 Fair Value** | **Carrying Amount** | **Level 2 Fair Value** |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 350 | $ 352 | $ 350 | $ 354 |
| Utility | 13,778 | 15,851 | 12,334 | 13,444 |

*Available for Sale Investments*

The following table provides a summary of available-for-sale investments:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| **As of December 31, 2014** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 17 | $ - | $ - | $ 17 |
| Global equity securities | 520 | 1,087 | (9) | 1,598 |
| Fixed-income securities | 1,059 | 75 | (4) | 1,130 |
| Total nuclear decommissioning trusts [(1)] | 1,596 | 1,162 | (13) | 2,745 |
| Other investments | 5 | 28 | - | 33 |
| **Total** | **$ 1,601** | **$ 1,190** | **$ (13)** | **$ 2,778** |
| **As of December 31, 2013** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 38 | $ - | $ - | $ 38 |
| Equity securities | | | | |
| U.S. | 246 | 811 | - | 1,057 |
| Non-U.S. | 215 | 242 | - | 457 |
| Debt securities | | | | |
| U.S. government and agency securities | 870 | 51 | (5) | 916 |
| Municipal securities | 24 | 2 | (1) | 25 |
| Other fixed-income securities | 163 | 1 | (2) | 162 |
| Total nuclear decommissioning trusts [(1)] | 1,556 | 1,107 | (8) | 2,655 |
| Other investments | 13 | 71 | - | 84 |
| **Total [(1)]** | **$ 1,569** | **$ 1,178** | **$ (8)** | **$ 2,739** |

[(1)] Represents amounts before deducting $324 million and $313 million at December 31, 2014 and 2013, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

| (in millions) | As of December 31, 2014 |
|---|---|
| Less than 1 year | $ 17 |
| 1–5 years | 466 |
| 5–10 years | 263 |
| More than 10 years | 384 |
| **Total maturities of debt securities** | **$ 1,130** |

The following table provides a summary of activity for the debt and equity securities:

| (in millions) | 2014 | 2013 | 2012 |
|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 1,336 | $ 1,619 | $ 1,133 |
| Gross realized gains on sales of securities held as available-for-sale | 118 | 94 | 19 |
| Gross realized losses on sales of securities held as available-for-sale | (12) | (13) | (17) |

## NOTE 11: EMPLOYEE BENEFIT PLANS

### Pension Plan and Postretirement Benefits Other than Pensions ("PBOP")

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans is zero.

PG&E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utility use a fiscal year-end measurement date for all plans.

### Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2014 and 2013:

***Pension Plan***

| (in millions) | 2014 | 2013 |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 12,527** | **$ 12,141** |
| Actual return on plan assets | 1,946 | 673 |
| Company contributions | 332 | 323 |
| Benefits and expenses paid | (589) | (610) |
| **Fair value of plan assets at end of year** | **$ 14,216** | **$ 12,527** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 14,077** | **$ 15,541** |
| Service cost for benefits earned | 383 | 468 |
| Interest cost | 695 | 627 |
| Actuarial (gain) loss | 2,131 | (1,950) |
| Plan amendments | (1) | - |
| Transitional costs | - | 1 |
| Benefits and expenses paid | (589) | (610) |
| **Benefit obligation at end of year** [1] | **$ 16,696** | **$ 14,077** |
| | | |
| **Funded Status:** | | |
| Current liability | $ (6) | $ (6) |
| Noncurrent liability | (2,474) | (1,544) |
| **Net liability at end of year** | **$ (2,480)** | **$ (1,550)** |

[1] PG&E Corporation's accumulated benefit obligation was $14.9 billion and $12.6 billion at December 31, 2014 and 2013, respectively.

***Postretirement Benefits Other than Pensions***

| (in millions) | 2014 | 2013 |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 1,892** | **$ 1,758** |
| Actual return on plan assets | 241 | 64 |
| Company contributions | 57 | 145 |
| Plan participant contribution | 63 | 64 |
| Benefits and expenses paid | (161) | (139) |
| **Fair value of plan assets at end of year** | **$ 2,092** | **$ 1,892** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 1,597** | **$ 1,940** |
| Service cost for benefits earned | 45 | 53 |
| Interest cost | 76 | 74 |
| Actuarial (gain) loss | 166 | (415) |
| Benefits paid | (140) | (123) |
| Federal subsidy on benefits paid | 4 | 4 |
| Plan participant contributions | 63 | 64 |
| **Benefit obligation at end of year** | **$ 1,811** | **$ 1,597** |
| | | |
| **Funded Status:** [1] | | |
| Noncurrent asset | $ 368 | $ 352 |
| Noncurrent liability | (87) | (57) |
| **Net asset at end of year** | $ **281** | $ **295** |

[1] At December 31, 2014 and 2013, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

***Pension Plan***

| **(in millions)** | **2014** | **2013** | **2012** |
|---|---|---|---|
| Service cost | $ 383 | $ 468 | $ 396 |
| Interest cost | 695 | 627 | 658 |
| Expected return on plan assets | (807) | (650) | (598) |
| Amortization of prior service cost | 20 | 20 | 20 |
| Amortization of net actuarial loss | 2 | 111 | 123 |
| **Net periodic benefit cost** | **293** | **576** | **599** |
| Less: transfer to regulatory account [1] | 42 | (238) | (301) |
| **Total expense recognized** | **$ 335** | **$ 338** | **$ 298** |

[1] The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

***Postretirement Benefits Other than Pensions***

| **(in millions)** | **2014** | **2013** | **2012** |
|---|---|---|---|
| Service cost | $ 45 | $ 53 | $ 49 |
| Interest cost | 76 | 74 | 83 |
| Expected return on plan assets | (103) | (79) | (77) |
| Amortization of transition obligation | - | - | 24 |
| Amortization of prior service cost | 23 | 23 | 25 |
| Amortization of net actuarial loss | 2 | 6 | 6 |
| **Net periodic benefit cost** | **$ 43** | **$ 77** | **$ 110** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax. In addition, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension benefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts that would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2015 are as follows:

| (in millions) | | Pension Plan | | PBOP Plans |
|---|---|---|---|---|
| Unrecognized prior service cost | $ | 15 | $ | 19 |
| Unrecognized net loss | | 11 | | 4 |
| **Total** | **$** | **26** | **$** | **23** |

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

**Valuation Assumptions**

In 2014, PG&E Corporation and the Utility adopted the Society of Actuaries 2014 Mortality Tables Report (RP-2014) and Mortality Improvement Scale (MP-2014 with modifications), which updated the mortality assumptions used for measuring retirement plan obligations. This new mortality table and improvement scale extends the assumed life expectancy of plan participants, resulting in an increase in PG&E Corporation's and the Utility's accrued benefit cost as of December 31, 2014. Total pension and postretirement benefit obligation increased $82 million and $18 million in 2014, respectively.

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | December 31, | | | December 31, | | |
| | 2014 | 2013 | 2012 | 2014 | 2013 | 2012 |
| **Discount rate** | 4.00 % | 4.89 % | 3.98 % | 3.89 - 4.09 % | 4.70 - 5.00 % | 3.75 - 4.08 % |
| **Rate of future compensation increases** | 4.00 % | 4.00 % | 4.00 % | - | - | - |
| **Expected return on plan assets** | 6.20 % | 6.50 % | 5.40 % | 3.30 - 6.70 % | 3.50 - 6.70 % | 2.90 - 6.10 % |

The assumed health care cost trend rate as of December 31, 2014 was 7.5%, decreasing gradually to an ultimate trend rate in 2024 and beyond of approximately 3.5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| (in millions) | | One-Percentage-Point Increase | | One-Percentage-Point Decrease |
|---|---|---|---|---|
| Effect on postretirement benefit obligation | $ | 107 | $ | (108) |
| Effect on service and interest cost | | 8 | | (8) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.2% compares to a ten-year actual return of 9.3%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 715 Aa-grade non-callable bonds at December 31, 2014. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

**Investment Policies and Strategies**

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs in financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts asset allocations are meant to manage volatility, reduce costs, and diversify its holdings. Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts's fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility, PG&E Corporation's and the Utility's trusts hold significant allocations in long maturity fixed-income investments. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Target allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening future funded status volatility. Derivative instruments such as equity index futures contracts are used to maintain existing equity exposure while adding exposure to fixed-income securities. In addition, derivative instruments such as equity index futures and fixed income futures are used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also used to hedge a portion of the currency of the global equity investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | **2015** | **2014** | **2013** | **2015** | **2014** | **2013** |
| Global equity | 25 % | 25 % | 25 % | 31 % | 30 % | 28 % |
| Absolute return | 5 % | 5 % | 5 % | 3 % | 3 % | 4 % |
| Real assets | 10 % | 10 % | 10 % | 8 % | 8 % | 8 % |
| Fixed income | 60 % | 60 % | 60 % | 58 % | 59 % | 60 % |
| **Total** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** |

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

### Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2014 and 2013.

| | Fair Value Measurements | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | At December 31, | | | | | | | |
| | 2014 | | | | 2013 | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Plan:** | | | | | | | | |
| Short-term investments | $ 352 | $ 311 | $ - | **$ 663** | $ 70 | $ - | $ - | **$ 70** |
| Global equity | 918 | 2,311 | - | **3,229** | 1,123 | 2,363 | - | **3,486** |
| Absolute return | - | - | 577 | **577** | - | - | 554 | **554** |
| Real assets | 620 | - | 675 | **1,295** | 562 | - | 544 | **1,106** |
| Fixed-income | 2,068 | 5,718 | 638 | **8,424** | 1,448 | 5,104 | 625 | **7,177** |
| **Total** | **$ 3,958** | **$ 8,340** | **$ 1,890** | **$14,188** | **$ 3,203** | **$ 7,467** | **$ 1,723** | **$12,393** |
| **PBOP Plans:** | | | | | | | | |
| Short-term investments | $ 28 | $ - | $ - | **$ 28** | $ 31 | $ - | $ - | **$ 31** |
| Global equity | 124 | 549 | - | **673** | 127 | 504 | - | **631** |
| Absolute return | - | - | 55 | **55** | - | - | 53 | **53** |
| Real assets | 72 | - | 49 | **121** | 67 | - | 38 | **105** |
| Fixed-income | 163 | 1,055 | 1 | **1,219** | 137 | 936 | 2 | **1,075** |
| **Total** | **$ 387** | **$ 1,604** | **$ 105** | **$ 2,096** | **$ 362** | **$ 1,440** | **$ 93** | **$ 1,895** |
| **Total plan assets at fair value** | | | | **$16,284** | | | | **$14,288** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $24 million and $131 million at December 31, 2014 and 2013, respectively. These net assets and net liabilities were comprised primarily of cash, accounts receivable, accounts payable, and deferred taxes.

### Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

***Short-Term Investments***

Historically, short-term investments consisted primarily of commingled funds of U.S. government short-term securities that were considered Level 1 assets and valued at the net asset value of $1 per unit.

In 2014, PG&E began diversifying these short-term investments across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

***Global Equity***

The global equity category includes investments in common stock, equity-index futures, and commingled funds comprised of equity securities spread across multiple industries and regions of the world. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets. Commingled funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled funds are categorized as Level 1 and Level 2 assets.

***Absolute Return***

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

***Real Assets***

The real asset category includes portfolios of commodity futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models, and valuation inputs that are unobservable and are considered Level 3 assets.

***Fixed-Income***

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments. Commingled funds are considered Level 2 assets. Corporate fixed-income also includes privately placed debt portfolios which are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on benchmark yields created using observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and Treasury futures. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

**Transfers Between Levels**

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No material transfers between levels occurred in the years ended December 31, 2014 and 2013.

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2014 and 2013:

| (in millions)<br>For the year ended December 31, 2014 | Pension Plan<br>Absolute Return | Fixed-Income | Real Assets | Total |
|---|---|---|---|---|
| Balance at beginning of year | $ 554 | $ 625 | $ 544 | $ **1,723** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 23 | 24 | 54 | **101** |
| Relating to assets sold during the period | - | 4 | - | **4** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | - | 1 | 78 | **79** |
| Settlements | - | (16) | (1) | **(17)** |
| **Balance at end of year** | **$ 577** | **$ 638** | **$ 675** | **$ 1,890** |

| (in millions)<br>For the year ended December 31, 2013 | Pension Plan<br>Absolute Return | Fixed-Income | Real Assets | Total |
|---|---|---|---|---|
| Balance at beginning of year | $ 513 | $ 611 | $ 285 | **$ 1,409** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 37 | 1 | 49 | **87** |
| Relating to assets sold during the period | 4 | - | (3) | **1** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | - | 20 | 352 | **372** |
| Settlements | - | (7) | (139) | **(146)** |
| **Balance at end of year** | **$ 554** | **$ 625** | **$ 544** | **$ 1,723** |

| (in millions)<br>For the year ended December 31, 2014 | PBOP Plans<br>Absolute Return | Fixed-Income | Real Assets | Total |
|---|---|---|---|---|
| Balance at beginning of year | $ 53 | $ 2 | 38 | **$ 93** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 2 | - | 4 | **6** |
| Relating to assets sold during the period | - | - | - | **-** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | - | - | 7 | **7** |
| Settlements | - | (1) | - | **(1)** |
| **Balance at end of year** | **$ 55** | **$ 1** | **$ 49** | **$ 105** |

| (in millions)<br>For the year ended December 31, 2013 | PBOP Plans<br>Absolute Return | Fixed-Income | Real Assets | Total |
|---|---|---|---|---|
| Balance at beginning of year | $ 49 | $ 1 | 28 | **$ 78** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 4 | - | 3 | **7** |
| Relating to assets sold during the period | - | - | - | **-** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | 12 | 1 | 21 | **34** |
| Settlements | (12) | - | (14) | **(26)** |
| **Balance at end of year** | **$ 53** | **$ 2** | **$ 38** | **$ 93** |

There were no material transfers out of Level 3 in 2014 and 2013.

**Cash Flow Information**

***Employer Contributions***

PG&E Corporation and the Utility contributed $332 million to the pension benefit plans and $57 million to the other benefit plans in 2014. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2014. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $61 million to the pension plan and other postretirement benefit plans, respectively, for 2015.

***Benefits Payments and Receipts***

As of December 31, 2014, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

| (in millions) | Pension Plan | PBOP Plans | Federal Subsidy |
|---|---|---|---|
| 2015 | $ 653 | $ 91 | $ (7) |
| 2016 | 696 | 96 | (8) |
| 2017 | 737 | 102 | (8) |
| 2018 | 775 | 109 | (9) |
| 2019 | 812 | 115 | (10) |
| Thereafter in the succeeding five years | 4,545 | 614 | (29) |

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

**Retirement Savings Plan**

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were $80 million, $71 million, and $67 million in 2014, 2013, and 2012, respectively.

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

**NOTE 12: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the California Power Exchange wholesale electricity markets during this period.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC.

Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers through resolution of the remaining disputed claims, either through settlement or through the conclusion of the various FERC and judicial proceedings, are refunded to customers through rates in future periods.

Interest accrues on the remaining net disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates, these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims, the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims and when such interest is paid.

In July 2014, a settlement agreement between the Utility and an electric supplier became effective, resolving a portion of the Utility's disputed claims. The settlement will result in refunds to customers of $312 million and will be returned through rates in future periods. The Utility is uncertain when and how the remaining disputed claims will be resolved.

In August 2014, the Utility received a letter from the California Power Exchange clarifying its ultimate intent to offset the Utility's remaining disputed claims principal and interest balances through net settlement. Accordingly, the Utility has presented $434 million of net Disputed claims and customer refunds on the Consolidated Balance Sheets at December 31, 2014, which includes both principal and interest. At December 31, 2013, the Consolidated Balance Sheets reflected $154 million of Disputed claims and customer refunds and $710 million of Interest payable.

At December 31, 2014 and 2013, the Utility held $291 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

**NOTE 13: RELATED PARTY AGREEMENTS AND TRANSACTIONS**

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2014** | **2013** | **2012** |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 5 | $ 7 | $ 7 |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 54 | $ 45 | $ 50 |
| Utility employee benefit due to PG&E Corporation | 70 | 57 | 51 |

At December 31, 2014 and 2013, the Utility had receivables of $17 million and $22 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $20 million and $17 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

**NOTE 14: CONTINGENCIES AND COMMITMENTS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below.

**Enforcement and Litigation Matters**

On September 9, 2010, a natural gas transmission pipeline owned and operated by the Utility ruptured in San Bruno, California. The ensuing explosion and fire resulted in the deaths of eight people, numerous personal injuries, and extensive property damage. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been materially affected by the costs the Utility has incurred related to shareholder funded safety work, the ongoing regulatory investigations, and civil lawsuits that commenced following the San Bruno accident.

***CPUC Investigations Regarding the Utility's Gas Transmission System and the San Bruno Accident***

There are three CPUC investigative enforcement proceedings pending against the Utility. These investigations relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident.

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in the three investigative enforcement proceedings pending against the Utility related to the Utility's natural gas transmission operations and practices and the San Bruno accident. The ALJs determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision calling for total fines and disallowances of $1.4 billion on the Utility to address all violations, allocated as follows: (1) $950 million fine to be paid to the State General Fund, (2) $400 million refund to ratepayers of previously authorized revenues, and (3) remedial measures that the ALJs estimate will cost the Utility at least $50 million. The ALJs' decisions are not the final decisions of the CPUC. Three CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. In addition, the Utility and other parties, including the SED, TURN, the ORA, the City and County of San Francisco, and the City of San Bruno have appealed the presiding officer decisions.

In its appeals, the Utility argued that the penalties imposed and the findings and conclusions on which they are based do not meet applicable legal standards, are based on the misapplication of California law and regulations, and are unconstitutional. The Utility has asked the CPUC to order the Utility to pay a significantly reduced penalty that is reasonable and proportionate in light of the nature of the violations and that takes into account the substantial unrecovered amounts the Utility has already spent and forecasts that it will spend on gas system safety. The Utility requested that it be allowed 180 days to raise the funds it may be ordered to pay to the State General Fund rather than the 40 days specified in the decision. The Utility also argued that the entire penalty should go toward funding investments in the Utility's gas transmission system. TURN, the ORA, and the City and County

of San Francisco jointly filed an appeal urging the CPUC to disallow the Utility's recovery of remaining PSEP costs of $877 million and to require the Utility to pay $473 million to the State General Fund. These parties also argue that the record in the investigative proceedings would support an even larger penalty than stated in the decision. The City of San Bruno appealed the rejection of its proposals for the appointment of an independent monitor to oversee the Utility's natural gas operations and for the establishment of a pipeline safety trust. It is uncertain when the final outcome of the investigations will be determined.

While the various appeals and requests for review of the presiding officer decisions are unresolved there continues to be significant uncertainty about the ultimate forms and amounts of penalties (including fines) that will be imposed on the Utility. At December 31, 2014, the Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable. The impact on PG&E Corporation's and the Utility's Consolidated Financial Statements will depend on the amounts and forms of penalties that are ultimately adopted by the CPUC. Fines payable to the State General Fund or refunds of revenues would be charged to net income when it is probable that such fines or refunds will be imposed and the amounts can be reasonably estimated. A disallowance of previously authorized and incurred capital costs would be charged to net income when the disallowance is probable and the amount can be reasonably estimated. Penalties in the form of future disallowed costs would be charged to net income in the period during which the actual costs are incurred. Although PG&E Corporation and the Utility believe it is probable that the CPUC will impose total penalties materially in excess of the $200 million previously accrued, they are unable to make a better estimate due to the variety of potential combinations of amounts and forms of penalties that could ultimately be imposed on the Utility and uncertainty about the timing of recognition. PG&E Corporation and the Utility believe the final outcome of the investigations will have a material impact on their financial condition, results of operations, and cash flows.

***Federal Criminal Indictment***

On July 29, 2014, a federal grand jury in the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts (increased from 12 counts charged in the original indictment) alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges an alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. A status conference is scheduled to be held in court on March 9, 2015. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their consolidated financial statements as such amounts are not considered to be probable.

***Other Enforcement Matters***

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters.

*Improper CPUC Communications*

On September 15, 2014, the Utility notified the CPUC and the ALJ overseeing the 2015 GT&S rate case that it believes certain communications between the Utility and CPUC personnel relating to the 2015 GT&S rate case violated the CPUC's rules regarding ex parte communications. Ex parte communications include any communication between a decision maker and an interested person concerning substantive issues in certain identified categories of formal proceedings before the CPUC. (The Utility discovered the communications as part of an internal review of communications between the Utility and the CPUC undertaken after the City of San Bruno filed a motion at the CPUC in late July 2014 alleging that various email communications between the Utility's employees and CPUC personnel violated the ex parte communication rules with respect to the pending CPUC investigative enforcement proceedings against the Utility. The Utility believes that the communications cited by San Bruno in its July 2014 motion are not prohibited ex parte communications. The CPUC has not yet addressed San Bruno's motion and its request that the CPUC penalize the Utility.)

On November 20, 2014, the CPUC issued a decision imposing a fine of $1.05 million on the Utility and disallowing up to the entire amount of the revenue increase that would have been collected from ratepayers over the five-month period between March 2015 and August 2015. The exact amount of the revenue disallowance will be determined in the CPUC's final decision in the GT&S rate case expected to be issued in August 2015. In addition, the decision prohibits the Utility from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors in any rate-setting proceeding and requires the Utility to report communications with senior CPUC staff, in any rate-setting or adjudicatory proceeding before the CPUC, for one year from the effective date of the decision. With respect to the GT&S rate case, the ban will be in effect until the resolution of the GT&S rate case or one year from the effective date of the decision, whichever is later. The Utility and other parties have requested that the CPUC reconsider its decision. The ORA, TURN, and the City of San Bruno argue that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million. It is uncertain when the CPUC will address these applications for rehearing.

In October and December 2014, the Utility notified the CPUC of additional email communications between the Utility and CPUC personnel regarding various matters (not limited to the GT&S rate case), that the Utility believes may constitute or describe ex parte communications. As of January 30, 2015, the Utility had provided copies of approximately 65,000 email communications between the CPUC and the Utility to the CPUC and the City of San Bruno. It is uncertain whether any of these email communications will be challenged as prohibited ex parte communications or as improper or illegal.

The Utility believes it is probable that CPUC enforcement actions will be taken in connection with these additional ex parte communications but is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties. It is also possible that other parties may request that the CPUC rescind decisions or take other action in open or closed proceedings to address ex parte communications that they may allege occurred regarding substantive issues in those proceedings. For example, TURN and the ORA have filed petitions to request that the CPUC rescind a $29 million shareholder incentive awarded to the Utility in 2010 for the successful implementation of the Utility's 2006-2008 energy efficiency programs based on their allegation that prohibited ex parte communications tainted the decision. It is uncertain whether the CPUC will grant these petitions or whether parties will request the CPUC to take action in other proceedings. It is also uncertain whether the ex parte communication issues will affect the outcome of other pending legal matters, ratemaking or regulatory proceedings, investigations and enforcement matters.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office have begun investigations in connection with these communications. The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility.

*Gas Safety Citation Program*

The SED, the division of the CPUC primarily responsible for overseeing the safety of electric and natural gas utility operations in California, conducts periodic audits of the Utility's operating practices and investigates potential violations. In December 2011 the CPUC adopted a gas safety citation program and delegated authority to the SED to issue citations and impose fines on California gas corporations, such as the Utility, for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The California gas corporations are required to inform the SED of self-

identified or self-corrected violations. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken.

Since the gas safety program became effective, the Utility has filed approximately 84 self-reports and the SED has imposed fines ranging from $50,000 to $16.8 million (including the $10.85 million fine related to an explosion in Carmel, California that is discussed below) for violations identified through self-reports, SED investigations and audits. The SED recently has stated that it will not conduct further investigations into 65 self-reports the Utility had filed through December 31, 2014. The Utility believes it is probable that the SED will impose fines or take other enforcement action with respect to some of the Utility's remaining self-reports or other self-reports that the Utility has filed since January 1, 2015. The Utility believes it is reasonably possible that the SED will impose fines on the Utility based on allegations of noncompliance that are contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

*Carmel Incident*

On March 3, 2014, a vacant house in Carmel, California was severely damaged due to a natural gas explosion while the Utility's employees were performing work to upgrade the main natural gas distribution pipeline in the area. There were no injuries or fatalities. The SED conducted an investigation of the incident and alleged that the Utility committed two violations of certain natural gas safety regulations by failing to follow procedures to update records, to provide its welding crew with accurate information, and to take steps to make safe any actual or potential hazard to life or property. On November 20, 2014, the SED issued a citation to the Utility that included a fine of $10.85 million for these alleged violations. The Utility recorded this amount as an expense for 2014. The Utility has appealed the citation to the CPUC. The SED has requested that the CPUC dismiss the Utility's appeal as untimely. The CPUC has not yet addressed the SED's request. In addition, the Utility was informed that the U.S. Attorney's Office was investigating the Carmel incident. It is uncertain whether any charges will be brought against the Utility.

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC issued an order instituting a new investigation into whether the Utility violated applicable laws pertaining to record-keeping practices for its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found.

In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014. (See "Carmel Incident" above.) On December 22, 2014, as directed by the CPUC, the Utility submitted a report that explained why the Utility believes the SED's investigative findings do not constitute violations of law and also outlined the various programs, measures and actions the Utility has undertaken to continuously improve its distribution record keeping practices.

PG&E Corporation and the Utility believe it is reasonably possible that the CPUC will impose fines on the Utility or take other enforcement action in connection with this matter, but are unable to reasonably estimate the amount or range of future loss contingencies.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

***Pipeline Safety Enhancement Plan***

On November 20, 2014, the CPUC approved the settlement agreement (submitted in July 2014) among the Utility, ORA, and TURN to resolve the Utility's PSEP Update application. The CPUC decision approved total PSEP-related revenue requirements (2012-2014) of $223 million, subject to refund, that reflect a $23 million reduction to expense funding, as compared to the amount requested in the Utility's application. (PG&E Corporation's and the Utility's 2014 consolidated financial statements reflect this reduction.) In accordance with the settlement agreement, the CPUC decision did not adopt any reduction to the Utility's request for authorization of total PSEP capital costs of $766 million. The Utility previously recorded cumulative charges of $549 million for PSEP-related capital costs that are expected to exceed the authorized amount. During the quarter ended December 31, 2014, the Utility recorded an additional charge for $116 million for PSEP capital costs that are expected to exceed the authorized amounts, bringing the total cumulative charge to $665 million. $209 million is expected to be incurred in 2015 and beyond. At December 31, 2014, approximately $549 million of PSEP-related capital costs is recorded in property, plant, and equipment on the Consolidated Balance Sheets. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected or if the Utility was required to refund previously authorized PSEP-related capital and expense amounts and/or revenue requirements.

**Other Legal and Regulatory Contingencies**

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred.

Accruals for other legal and regulatory contingencies (excluding amounts related to natural gas matters above) totaled $55 million at December 31, 2014 and $43 million at December 31, 2013. These amounts are included in other current liabilities in the Consolidated Balance Sheets. The estimated reasonably possible range of loss for these matters in excess of the recorded accrual is not material. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Environmental Remediation Contingencies**

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **December 31, 2014** | **December 31, 2013** |
| Topock natural gas compressor station [1] | $ 291 | $ 264 |
| Hinkley natural gas compressor station [1] | 158 | 190 |
| Former manufactured gas plant sites owned by the Utility or third parties | 257 | 184 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites | 150 | 160 |
| Fossil fuel-fired generation facilities and sites | 98 | 102 |
| **Total environmental remediation liability** | **$ 954** | **$ 900** |

(1) See "Natural Gas Compressor Station Sites" below.

At December 31, 2014 the Utility expected to recover $663 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

***Natural Gas Compressor Station Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as the "Topock site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

*Hinkley Site*

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. In 2013, the Regional Board certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. On January 22, 2015, the Regional Board issued a preliminary draft clean-up and abatement order that proposes that the Utility continue and improve its remedial treatment methods evaluated in the environmental report, along with a proposed monitoring and reporting program and proposed deadlines in 2021 and 2026 to meet specified interim clean-up targets. Comments by the Utility and the public are due on March 13, 2015. The Regional Board is tentatively scheduled to consider final adoption of the clean-up and abatement order at its September 2015 meeting.

The Utility's environmental remediation liability at December 31, 2014 reflects the Utility's best estimate of probable future costs associated with its final remediation plan and interim remediation measures. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, and the nature and extent of the chromium contamination. As the comment process continues and the final order and permits are issued, the Utility expects to obtain additional information about the total costs associated with implementing the final remedy and performing related activities and the best estimate of future costs may be subject to further changes. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

*Topock Site*

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. In September 2014, the Utility submitted its 90% remedial design plan to regulatory authorities and expects to submit its final remedial design plan in mid-2015, which would seek approval to begin construction of an in-situ groundwater treatment system that will convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River. The Utility's environmental remediation liability at December 31, 2014 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

***Reasonably Possible Environmental Contingencies***

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.8 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations during the period in which they are recorded.

**Nuclear Insurance**

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages. If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2014, the current maximum aggregate annual retrospective premium obligation for the Utility is approximately $51 million.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $13.6 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $13.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a maximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident. In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the liability insurance.

**Purchase Commitments**

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2014:

| | Power Purchase Agreements | | | | | |
|---|---|---|---|---|---|---|
| (in millions) | Renewable Energy | Qualifying Facility | Other | Natural Gas | Nuclear Fuel | Total |
| 2015 | $ 2,145 | $ 601 | $ 820 | $ 544 | $ 138 | $ 4,248 |
| 2016 | 2,185 | 525 | 766 | 164 | 129 | 3,769 |
| 2017 | 2,187 | 418 | 758 | 107 | 131 | 3,601 |
| 2018 | 2,063 | 382 | 731 | 107 | 115 | 3,398 |
| 2019 | 2,053 | 304 | 706 | 107 | 109 | 3,279 |
| Thereafter | 30,289 | 1,217 | 2,390 | 648 | 429 | 34,973 |
| **Total purchase commitments** | **$ 40,922** | **$ 3,447** | **$ 6,171** | **$ 1,677** | **$ 1,051** | **$ 53,268** |

***Third-Party Power Purchase Agreements***

In the ordinary course of business, the Utility enters into various agreements, including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

*Renewable Energy Power Purchase Agreements* – In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow significantly. As of December 31, 2014, renewable energy contracts expire at various dates between 2016 and 2043.

*Qualifying Facility Power Purchase Agreement* – The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Several of these agreements are treated as capital leases. At December 31, 2014 and 2013, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $74 million and $97 million including accumulated amortization of $128 million and $176 million. The present value of the future minimum lease payments due under these agreements included $20 million and $23 million in Current Liabilities and $54 million and $74 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2014, QF contracts in operation expire at various dates between 2015 and 2028 .

*Other Power Purchase Agreements* – The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power. As of December 31, 2014, other power purchase agreements expire at various dates between 2015 and 2033.

The costs incurred for all power purchases and electric capacity amounted to $3.6 billion in 2014, $3.0 billion in 2013, and $2.3 billion in 2012.

### *Natural Gas Supply, Transportation, and Storage Commitments*

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. These purchase agreements expire at various dates between 2015 and 2026. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $1.4 billion in 2014, $1.6 billion in 2013, and $1.3 billion in 2012.

### *Nuclear Fuel Agreements*

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2015 and 2025 and are intended to ensure long-term nuclear fuel supply. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to $105 million in 2014, $162 million in 2013, and $118 million in 2012.

## Other Commitments

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2015 and 2052. At December 31, 2014, the future minimum payments related to these commitments were as follows:

| **(in millions)** | **Operating Leases** |
|---|---|
| 2015 | $ 44 |
| 2016 | 43 |
| 2017 | 33 |
| 2018 | 30 |
| 2019 | 27 |
| Thereafter | 183 |
| **Total minimum lease payments** | **$ 360** |

Payments for other commitments related to operating leases amounted to $42 million in 2014, $40 million in 2013, and $32 million in 2012. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

**QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)**

| | Quarter ended | | | |
|---|---|---|---|---|
| (in millions, except per share amounts) | December 31 | September 30 | June 30 | March 31 |
| **2014** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues [1] | $ 4,308 | $ 4,939 | $ 3,952 | $ 3,891 |
| Operating income | 383 | 1,065 | 518 | 484 |
| Income tax provision | 35 | 115 | 104 | 91 |
| Net income [2] | 135 | 814 | 271 | 230 |
| Income available for common shareholders | 131 | 811 | 267 | 227 |
| Comprehensive income | 120 | 796 | 260 | 235 |
| Net earnings per common share, basic | 0.28 | 1.72 | 0.57 | 0.49 |
| Net earnings per common share, diluted | 0.27 | 1.71 | 0.57 | 0.49 |
| Common stock price per share: | | | | |
| High | 54.98 | 48.07 | 48.23 | 44.73 |
| Low | 44.38 | 43.00 | 42.37 | 39.60 |
| **UTILITY** | | | | |
| Operating revenues [1] | $ 4,308 | $ 4,939 | $ 3,951 | $ 3,890 |
| Operating income | 383 | 1,059 | 525 | 485 |
| Income tax provision | 59 | 115 | 110 | 100 |
| Net income [2] | 162 | 793 | 250 | 228 |
| Income available for common stock | 158 | 790 | 246 | 225 |
| Comprehensive income | 154 | 793 | 250 | 228 |
| | | | | |
| **2013** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 3,975 | $ 4,175 | $ 3,776 | $ 3,672 |
| Operating income | 333 | 291 | 636 | 502 |
| Income tax (benefit) provision | 25 | (24) | 153 | 114 |
| Net income [2] | 90 | 164 | 332 | 242 |
| Income available for common shareholders | 86 | 161 | 328 | 239 |
| Comprehensive income | 210 | 165 | 352 | 252 |
| Net earnings per common share, basic | 0.19 | 0.36 | 0.74 | 0.55 |
| Net earnings per common share, diluted | 0.19 | 0.36 | 0.74 | 0.55 |
| Common stock price per share: | | | | |
| High | 42.75 | 46.37 | 48.44 | 44.53 |
| Low | 40.07 | 40.76 | 43.59 | 40.47 |
| **UTILITY** | | | | |
| Operating revenues | $ 3,973 | $ 4,174 | $ 3,775 | $ 3,671 |
| Operating income | 360 | 292 | 635 | 503 |
| Income tax (benefit) provision | 65 | (20) | 160 | 121 |
| Net income [2] | 138 | 162 | 329 | 237 |
| Income available for common stock | 134 | 159 | 325 | 234 |
| Comprehensive income | 231 | 166 | 333 | 242 |

[1] In the third quarter 2014, the Utility recorded an increase to base revenues as authorized by the CPUC in the 2014 GRC decision.
[2] The Utility recorded a charge to net income of $116 million in the fourth quarter of 2014 and $196 million in the third quarter of 2013 for PSEP capital costs that are forecasted to exceed the authorized amounts. (See Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of PG&E Corporation and Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2014.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2014, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2014 of the Company and the Utility and our report dated February 10, 2015 expressed an unqualified opinion on those financial statements and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 10, 2015

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2014 and 2013, and the Company's related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 to the consolidated financial statements, there are three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 10, 2015 expressed an unqualified opinion on the Company's and the Utility's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 10, 2015

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

## ITEM 9A. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2014, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

## ITEM 9B. OTHER INFORMATION

Not applicable.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this report. Other information regarding directors is set forth under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act is included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on PG&E Corporation's website *www.pgecorp.com*, and the Utility's website, *www.pge.com*: (1) the codes of conduct and ethics adopted by PG&E Corporation and the Utility applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and the Utility that apply to their respective Chief Executive Officers, Chief Financial Officers, or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within four business days of the waiver.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

During 2014, there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial expert" as defined by the SEC is set forth under the headings "Corporate Governance – Board Committee Duties – Audit Committees" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 11. EXECUTIVE COMPENSATION

Information responding to Item 11, for each of PG&E Corporation and the Utility, is set forth under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2014," "Grants of Plan-Based Awards in 2014," "Outstanding Equity Awards at Fiscal Year End - 2014," "Option Exercises and Stock Vested During 2014," "Pension Benefits – 2014," "Non-Qualified Deferred Compensation – 2014," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2014 Director Compensation" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Equity Compensation Plan Information***

The following table provides information as of December 31, 2014 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|---|---|---|---|
| Equity compensation plans approved by shareholders | 6,303,612 [1] | $ 34.83 [2] | 16,184,126 [3] |
| Equity compensation plans not approved by shareholders | - | - | - |
| Total equity compensation plans | 6,303,612 [1] | $ 34.83 [2] | 16,184,126 [3] |

[1] Includes 45,660 phantom stock units, 2,571,530 restricted stock units and 3,659,066 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares granted in 2012, reflects the actual payout percentage of 35%. The actual number of shares issued can range from 0% to 200% of target depending on achievement of total shareholder return objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

[2] This is the weighted average exercise price for the 26,756 options outstanding as of December 31, 2014.

[3] Represents the total number of shares available for issuance under all of PG&E Corporation's equity compensation plans as of December 31, 2014. Stock-based awards granted under these plans include restricted stock units, performance shares and phantom stock units. The 2014 LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the 2014 LTIP, less approximately 2.7 million shares for awards granted under the 2006 LTIP from January 1, 2014 through May 11, 2014. In addition, if any awards outstanding under the 2006 LTIP at December 31, 2013 are cancelled, forfeited or expire without being settled in full, shares of stock allocable to the terminated portion of such awards shall again be available for issuance under the 2014 LTIP.

For more information, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements appearing in Item 8.

## ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information responding to Item 13, for each of PG&E Corporation and the Utility, is included under the headings "Related Party Transactions" and "Corporate Governance – Board and Director Independence and Qualifications" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 14. Principal Accountant Fees and Services

Information responding to Item 14, for each of PG&E Corporation and the Utility, is set forth under the heading "Information Regarding the Independent Registered Public Accounting Firm for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## PART IV

### ITEM 15. Exhibits and Financial Statement Schedules

**(a) The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as part of this report in Item 8:

Consolidated Statements of Income for the Years Ended December 31, 2014, 2013, and 2012 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2014 and 2013 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013, and 2012 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2014, 2013, and 2012 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2014, 2013, and 2012 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Management's Report on Internal Controls

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Report of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2014 and 2013 and for the Years Ended December 31, 2014, 2013, and 2012.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2014, 2013, and 2012.

3. Exhibits required by Item 601 of Regulation S-K

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of February 19, 2014 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of February 19, 2014 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended March 31, 2014 (File No. 1-2348), Exhibit 3.2) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility’s issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |

| | |
|---|---|
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No. 12348), Exhibit 4.1) |

| | |
|---|---|
| 4.20 | Twenty-Second Supplemental Indenture, dated as of May 12, 2014, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due May 11, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 12, 2014 (File No. 12348), Exhibit 4.1) |
| 4.21 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 12348), Exhibit 4.1) |
| 4.22 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 12348), Exhibit 4.1) |
| 4.23 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.24 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |
| 4.25 | Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1) |
| 4.26 | First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2) |
| 10.1 | Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |

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| 10.4 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation’s and Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.5 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.6 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.11 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5) |
| 10.12 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.13 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.14 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.15 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5) |
| 10.16 | * | Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.17 | * | Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18) |
| 10.18 | * | Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18) |
| 10.19 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |

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| 10.20 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.21 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.22 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.23 | * | Separation Agreement between PG&E Corporation and Greg Pruett dated August 8, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-12609), Exhibit 10.1) |
| 10.24 | * | Separation Agreement between Pacific Gas and Electric Company and Thomas Bottorff dated September 17, 2014 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-2348), Exhibit 10.2) |
| 10.25 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Steven Malnight dated February 22, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-2348), Exhibit 10.3) |
| 10.26 | * | Amended and Restated Restricted Stock Unit Agreement between C. Lee Cox and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.6) |
| 10.27 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.28 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.29 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.30 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.31 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.1) |
| 10.32 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.33 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.34 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.35 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |

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| 10.36 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30) |
| 10.37 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6, 2015 |
| 10.38 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.39 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.40 | * | Resolution of the PG&E Corporation Board of Directors dated September 16, 2014, adopting director compensation arrangement effective January 1, 2015 |
| 10.41 | * | Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36) |
| 10.42 | * | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 16, 2014, adopting director compensation arrangement effective January 1, 2015 |
| 10.43 | * | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37) |
| 10.44 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2015 |
| 10.45 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.46 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.47 | * | Form of Restricted Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.48 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.49 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.50 | * | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.51 | * | Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.52 | * | Form of Restricted Stock Unit Agreement for 2014 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.3) |

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| 10.53 | * | Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.54 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.55 | * | Form of Performance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.56 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |
| 10.57 | * | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.58 | * | Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.59 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.60 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.61 | * | PG&E Corporation Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.62 | * | PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6) |
| 10.63 | * | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.64 | * | PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51) |
| 10.65 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.66 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.67 | * | PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1) |
| 10.68 | * | PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39) |
| 10.69 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |

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| 10.70 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.71 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23 | | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |

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| * | Management contract or compensatory agreement. |
| ** | Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report. |

## SIGNATURES

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2014 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| PG&E CORPORATION (Registrant) | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) |
|---|---|
| ANTHONY F. EARLEY, JR. | CHRISTOPHER P. JOHNS |
| Anthony F. Earley, Jr. | Christopher P. Johns |
| By: Chairman of the Board, Chief Executive Officer, and President | By: President |
| Date: February 10, 2015 | Date: February 10, 2015 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| **A. Principal Executive Officers** | | |
| ANTHONY F. EARLEY, JR. | Chairman of the Board, Chief Executive Officer, and | February 10, 2015 |
| Anthony F. Earley, Jr. | President (PG&E Corporation) | |
| CHRISTOPHER P. JOHNS | President | February 10, 2015 |
| Christopher P. Johns | (Pacific Gas and Electric Company) | |
| **B. Principal Financial Officers** | | |
| KENT M. HARVEY | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 10, 2015 |
| Kent M. Harvey | | |
| DINYAR B. MISTRY | Vice President, Chief Financial Officer, and Controller | February 10, 2015 |
| Dinyar B. Mistry | (Pacific Gas and Electric Company) | |
| **C. Principal Accounting Officer** | | |
| DINYAR B. MISTRY | Vice President and Controller (PG&E Corporation) | February 10, 2015 |
| Dinyar B. Mistry | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | |

**D. Directors**

| | | |
|---|---|---|
| * LEWIS CHEW<br>Lewis Chew | Director | February 10, 2015 |
| * ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Director | February 10, 2015 |
| * FRED J. FOWLER<br>Fred J. Fowler | Director | February 10, 2015 |
| * MARYELLEN C. HERRINGER<br>Maryellen C. Herringer | Director | February 10, 2015 |
| * CHRISTOPHER P. JOHNS<br>Christopher P. Johns | Director (Pacific Gas and Electric Company only) | February 10, 2015 |
| * RICHARD C. KELLY<br>Richard C. Kelly | Director | February 10, 2015 |
| * ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 10, 2015 |
| * RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 10, 2015 |
| * FORREST E. MILLER<br>Forrest E. Miller | Director | February 10, 2015 |
| * ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 10, 2015 |
| * BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 10, 2015 |
| * BARRY LAWSON WILLIAMS<br>Barry Lawson Williams | Director | February 10, 2015 |

*By: HYUN PARK
HYUN PARK, Attorney-in-Fact

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and the Company's and the Utility's internal control over financial reporting as of December 31, 2014, and have issued our reports thereon dated February 10, 2015 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties); such reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of the Company and Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 10, 2015

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2014** | **2013** | **2012** |
| Administrative service revenue | $ 51 | $ 41 | $ 43 |
| Operating expenses | (53) | (42) | (41) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (14) | (25) | (22) |
| Other expense | (1) | (57) | (39) |
| Equity in earnings of subsidiaries | 1,413 | 848 | 817 |
| Income before income taxes | 1,397 | 766 | 759 |
| Income tax benefit | 39 | 48 | 57 |
| **Net income** | **$ 1,436** | **$ 814** | **$ 816** |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $10, $80, and $72, at respective dates) | $ (14) | $ 113 | $ 108 |
| Net change in investments (net of taxes of $17, $26, and $3, at respective dates) | (25) | 38 | 4 |
| Total other comprehensive income (loss) | (39) | 151 | 112 |
| **Comprehensive Income** | **$ 1,397** | **$ 965** | **$ 928** |
| **Weighted Average Common Shares Outstanding, Basic** | **468** | **444** | **424** |
| **Weighted Average Common Shares Outstanding, Diluted** | **470** | **445** | **425** |
| **Earnings per common share, basic** | **$ 3.07** | **$ 1.83** | **$ 1.92** |
| **Earnings per common share, diluted** | **$ 3.06** | **$ 1.83** | **$ 1.92** |

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED BALANCE SHEETS**

| (in millions) | Balance at December 31, 2014 | Balance at December 31, 2013 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 96 | $ 231 |
| Advances to affiliates | 31 | 30 |
| Income taxes receivable | 29 | 13 |
| Other | 38 | 86 |
| **Total current assets** | **194** | **360** |
| **Noncurrent Assets** | | |
| Equipment | 2 | 2 |
| Accumulated depreciation | (1) | (1) |
| **Net equipment** | **1** | **1** |
| Investments in subsidiaries | 16,003 | 14,711 |
| Other investments | 117 | 110 |
| Income taxes receivable | - | 5 |
| Deferred income taxes | 260 | 188 |
| **Total noncurrent assets** | **16,381** | **15,015** |
| **Total Assets** | **$ 16,575** | **$ 15,375** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ - | $ 260 |
| Long-term debt classified as current | - | 350 |
| Accounts payable – other | 67 | 66 |
| Other | 269 | 230 |
| **Total current liabilities** | **336** | **906** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 350 | - |
| Other | 141 | 127 |
| **Total noncurrent liabilities** | **491** | **127** |
| **Common Shareholders' Equity** | | |
| Common stock | 10,421 | 9,550 |
| Reinvested earnings | 5,316 | 4,742 |
| Accumulated other comprehensive loss | 11 | 50 |
| **Total common shareholders' equity** | **15,748** | **14,342** |
| **Total Liabilities and Shareholders' Equity** | **$ 16,575** | **$ 15,375** |

**PG&E CORPORATION**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| **Cash Flows from Operating Activities:** | | | |
| Net income | $ 1,436 | $ 814 | $ 816 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 65 | 54 | 51 |
| Equity in earnings of subsidiaries | (1,413) | (848) | (817) |
| Deferred income taxes and tax credits, net | (72) | (10) | (31) |
| Noncurrent income taxes receivable/payable | 5 | - | (6) |
| Current income taxes receivable/payable | (16) | 20 | (82) |
| Other | 43 | (20) | 20 |
| **Net cash provided by (used in) operating activities** | **48** | **10** | **(49)** |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (978) | (1,371) | (1,023) |
| Dividends received from subsidiaries [(1)] | 716 | 716 | 716 |
| Proceeds from tax equity investments | 368 | 275 | 228 |
| Other | - | (8) | - |
| **Net cash provided by (used in) investing activities** | **106** | **(388)** | **(79)** |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings under revolving credit facilities | - | 140 | 120 |
| Repayments under revolving credit facilities | (260) | - | - |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $3 in 2014 | 347 | - | - |
| Repayments of long-term debt | (350) | - | - |
| Common stock issued | 802 | 1,045 | 751 |
| Common stock dividends paid [(2)] | (828) | (782) | (746) |
| Other | - | (1) | 1 |
| **Net cash provided by (used in) financing activities** | **(289)** | **402** | **126** |
| **Net change in cash and cash equivalents** | **(135)** | **24** | **(2)** |
| **Cash and cash equivalents at January 1** | **231** | **207** | **209** |
| **Cash and cash equivalents at December 31** | **$ 96** | **$ 231** | **$ 207** |
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (15) | $ (23) | $ (20) |
| Income taxes, net | 1 | 21 | (60) |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Noncash common stock issuances | 21 | 22 | 22 |
| Common stock dividends declared but not yet paid | $ 217 | $ 208 | $ 196 |

(1) Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries an investing cash flow.
(2) In January, April, July, and October of 2014, 2013, and 2012, respectively, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

**PG&E Corporation**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2014, 2013, and 2012**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions [2] | Balance at End of Period |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2014: | | | | | |
| Allowance for uncollectible accounts [1] | $ 80 | $ 41 | $ - | $ 55 | $ 66 |
| 2013: | | | | | |
| Allowance for uncollectible accounts [1] | $ 87 | $ 53 | $ - | $ 60 | $ 80 |
| 2012: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 66 | $ - | $ 60 | $ 87 |

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**Pacific Gas and Electric Company**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2014, 2013, and 2012**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions** [2] | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2014: | | | | | |
| Allowance for uncollectible accounts [1] | $ 80 | $ 41 | $ - | $ 55 | $ 66 |
| 2013: | | | | | |
| Allowance for uncollectible accounts [1] | $ 87 | $ 53 | $ - | $ 60 | $ 80 |
| 2012: | | | | | |
| Allowance for uncollectible accounts [1] | $ 81 | $ 66 | $ - | $ 60 | $ 87 |

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**EXHIBIT INDEX**

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of February 19, 2014 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of February 19, 2014 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended March 31, 2014 (File No. 1-2348), Exhibit 3.2) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility’s issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |

| | |
|---|---|
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No. 12348), Exhibit 4.1) |

| | |
|---|---|
| 4.20 | Twenty-Second Supplemental Indenture, dated as of May 12, 2014, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due May 11, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 12, 2014 (File No. 12348), Exhibit 4.1) |
| 4.21 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 12348), Exhibit 4.1) |
| 4.22 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 12348), Exhibit 4.1) |
| 4.23 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.24 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |
| 4.25 | Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1) |
| 4.26 | First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2) |
| 10.1 | Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |

| | | |
|---|---|---|
| 10.4 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.5 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.6 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.11 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5) |
| 10.12 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.13 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.14 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.15 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5) |
| 10.16 | * | Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4) |
| 10.17 | * | Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18) |
| 10.18 | * | Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18) |
| 10.19 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |

| | | |
|---|---|---|
| 10.20 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.21 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.22 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.23 | * | Separation Agreement between PG&E Corporation and Greg Pruett dated August 8, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-12609), Exhibit 10.1) |
| 10.24 | * | Separation Agreement between Pacific Gas and Electric Company and Thomas Bottorff dated September 17, 2014 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-2348), Exhibit 10.2) |
| 10.25 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Steven Malnight dated February 22, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-2348), Exhibit 10.3) |
| 10.26 | * | Amended and Restated Restricted Stock Unit Agreement between C. Lee Cox and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.6) |
| 10.27 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.28 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.29 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.30 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.31 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.1) |
| 10.32 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.33 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.34 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.35 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |

| | | |
|---|---|---|
| 10.36 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30) |
| 10.37 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6, 2015 |
| 10.38 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.39 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.40 | * | Resolution of the PG&E Corporation Board of Directors dated September 16, 2014, adopting director compensation arrangement effective January 1, 2015 |
| 10.41 | * | Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36) |
| 10.42 | * | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 16, 2014, adopting director compensation arrangement effective January 1, 2015 |
| 10.43 | * | Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37) |
| 10.44 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2015 |
| 10.45 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.46 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.47 | * | Form of Restricted Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.48 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.49 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.50 | * | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.51 | * | Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.52 | * | Form of Restricted Stock Unit Agreement for 2014 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.3) |

| | | |
|---|---|---|
| 10.53 | * | Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1) |
| 10.54 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.55 | * | Form of Performance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.56 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |
| 10.57 | * | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.58 | * | Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2) |
| 10.59 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.60 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.61 | * | PG&E Corporation Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.62 | * | PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6) |
| 10.63 | * | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.64 | * | PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51) |
| 10.65 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.66 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.67 | * | PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1) |
| 10.68 | * | PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39) |
| 10.69 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |

| | | |
|---|---|---|
| 10.70 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.71 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23 | | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

# Exhibit 4

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-K**

**(Mark One)**

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the Fis cal Year Ended December 31, 2015**

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from _________ to ___________**

| Commission File Number | Exact Name of Registrant as S pecified I n I ts C harter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

**PG&E Corporation.**
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

**Pacific Gas and Electric Company®**
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each c lass | Name of e ach e xchange on w hich r egistered |
|---|---|
| **PG&E Corporation:** Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company:** First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE Amex Equities |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | | |
|---|---|---|
| PG&E Corporation | Yes ☑ | No ☐ |
| Pacific Gas and Electric Company | Yes ☑ | No ☐ |

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 201 5 , the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $23,628 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |

**Common Stock outstanding as of February 12 , 201 6 :**

| | |
|---|---|
| PG&E Corporation: | 492,830,471 shares |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

| | |
|---|---|
| Designated portions of the Joint Proxy Statement relating to the 201 6 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |

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**UNITS OF MEASUREMENT**

| | | |
|---|---|---|
| 1 Kilowatt (kW) | = | One thousand watts |
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt (GW) | = | One million kilowatts |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |
| 1 Bcf | = | One billion cubic feet |
| 1 MDth | = | One thousand decatherms |

**GLOSSARY**

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2015 Form 10-K | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2015 |
| AB | Assembly Bill |
| AFUDC | allowance for funds used during construction |
| ALJ | administrative law judge |
| ARO | asset retirement obligation |
| ASU | accounting standard update |
| CAISO | California Independent System Operator |
| CARB | California Air Resources Board |
| CCA | Community Choice Aggregator |
| Central Coast Board | Central Coast Regional Water Quality Control Board |
| CEC | California Energy Resources Conservation and Development Commission |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DOE | Department of Energy |
| EPA | Environmental Protection Agency |
| EPS | earnings per common share |
| EV | electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| IRS | Internal Revenue Service |
| LTIP | long term incentive plan |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K |
| NEIL | Nuclear Electric Insurance Limited |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| ORA | Office of Ratepayer Advocates |
| PSEP | pipeline safety enhancement plan |
| QF | Qualifying facility |
| Regional Board | California Regional Water Quality Control Board, Lahontan Region |
| REITS | Global real estate investment trust |
| ROE | return on equity |
| RPS | renewable portfolio standard |
| SB | senate bill |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |
| Water Board | California State Water Resources Control Board |

## PART I

### ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found below in Item 6. Selected Financial Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

At December 31, 2015, PG&E Corporation and the Utility had approximately 23,000 regular employees, approximately 20 of which were employees of the PG&E Corporation . Of the Utility's regular employees, approximately 13,500 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW"); the Engineers and Scientists of California ("ESC"); and the Service Employees International Union ("SEIU" ). The SEIU collective bargaining agreement will expire on July 31, 201 6 . The two agreements with IBEW will expire on December 31, 201 6 . The agreement with ESC, originally scheduled to expire on December 31, 2015, automatically renewed for a period of one year pending the negotiation of a new agreement with the union. In January 2016, the Utility and ESC reached a tentative new agreement, subject to ratification by members of ESC. If ratified, the new agreement with ESC will be retroactive to January 1, 2016 and will expire on December 31, 2019 .

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, *www.pgecorp.com* , and the Utility's website, *www.pge.com* , as promptly as practicable after they are filed with, or furnished to, the SEC . The information contained on these websites is not part of this or any other report that PG&E Corporation and the Utility files with, or furnishes to, the SEC.

In April 2015, the CPUC issued decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record-keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record-keeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the pipeline accident that occurred in San Bruno, California on September 9, 2010 (the "San Bruno accident"). A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") to impose penalties on the Utility totaling $1.6 billion . For more information about the Penalty Decision see Item 1.A. Risk Factors and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below. The Utility also faces criminal charges in the U.S. District Court for the Northern District of California alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act and that the Utility obstructed the N TSB 's investigation into the cause of the San Bruno accident. T he trial currently is scheduled to begin on March 22, 2016. F or more information about the criminal proceeding, s ee "Enforcement and Litigation Matters" in MD&A , Item 1.A. Risk Factors, and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below .

This Annual Report on Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see "Item 1A. Risk Factors" and the section entitled "Cautionary Language Regarding Forward-Looking Statements" in MD&A.

#### Regulatory Environment

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is subject to the jurisdiction of the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies with respect to safety, the environment and health. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proc eedings affecting the Utility.

PG&E Corporation is a “public utility holding company” as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

*The California Public Utilities Commission*

The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electricity generation, and natural gas transmission and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $50,000 per day, per violation, for violations that occurred after January 1, 2012. (The statutory maximum penalty for violations that occurred before January 1, 2012 is $20,000 per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

As discussed above, i n April 2015, the CPUC concluded its three investigati ve enforcement actions against the Utility by imposing penalties totaling $1.6 billion. (For more information about the Penalty Decision , see Item 1.A. Risk Factors and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below.) The CPUC is also conducting investigative enforcement proceedings relating to the Utility’s natural gas distribution facilities record-keeping practices and the Utility’s potential violations of the CPUC’s ex parte communication rules. (See “Enforcement and Litigation Matters” in MD&A for more information.) Further, in August 2015, the CPUC began an investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. (For more information, see “ Regulatory Matters ” in MD&A.)

The CPUC has adopted separate gas and electric safety enforcement programs that authorize the SED to issue citations and impose fines for violations of certain regulations. Under both the gas and electric programs, the SED is required to impose the maximum statutory penalty o f $50,000 for each separate violation and has the discretion to impose daily fines for continuing violations. During 2016, the CPUC is expected to develop and implement improvements and refinements to the electric and gas safety citation programs, including steps to reconcile the differences between the two programs.

The California State Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to increasing renewable energy resources, the development and widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, the development of energy storage technologies and facilities, and the development of a state-wide electric vehicle charging infrastructure. T he CPUC is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs. The CPUC also conducts audits and reviews of the Utility’s accounting, performance and compliance with regulatory guidelines .

T he CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation’s Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see “Liquidity and Financial Resources” in MD&A and Item 1A. Risk Factors.)

*The Federal Energy Regulatory Commission and the California Independent System Operator*

The FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility's transmission systems with other electric systems and generation facilities, the tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation's electricity transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. The FERC has authority to impose fines of up to $1 million per day for violation of certain federal statutes and regulations.

The CAISO is the FERC-approved regional transmission organization for the Utility's service territory. The CAISO controls the operation of the electricity transmission system in California and provides open access transmission service on a non - discriminatory basis. The CAISO also is responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generation capacity, and ensuring that the reliability of the transmission system is maintained.

*The Nuclear Regulatory Commission*

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electric ity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. For more information about Diablo Canyon, see "Regulatory Matters – Diablo Canyon" in MD&A and Item 1.A Risk Factors below.)

***Other Regulation***

The CEC is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

The CARB is the state agency charged with setting and monitoring GHG and other emission limits. The CARB also is responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California. (See "Environmental Regulation — Air Quality and Climate Change" below.)

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and highway s. In exchange for the right to use public streets and highway s, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date.

**Ratemaking Mechanisms**

The Utility's rates for electricity and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service including a return on invested capital ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses ( e.g., maintenance, administration and general expenses) and capital costs ( e.g., depreciation, tax, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that it is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in MD&A) , including its costs to procure electricity, natural gas and nuclear fuel, to administer public purpose and customer programs, and to decommission its nuclear facilities.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. The authorized rate of return on all other assets is set in the CPUC's cost of capital proceeding. Other than its electric transmission and certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume. Regulatory balancing accounts, or revenue adjustment mechanisms, ensure that the Utility will fully collect its authorized base revenue requirements. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impact ed Earnings" in MD&A) within its authorized base revenue requirements.

Both gas and electric rates vary depending on seasons mostly due to the influence of weather. Gas service rates generally increase during the winter months (October through March) to account for the gas peak due to heating while electricity rates increase during summer (June – September) because of higher summer costs, driven by air conditioning loads.

During 2015, the CPUC continued to implement state law requirements to reform residential electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate) , and allow customers to have greater control over their energy use. (See "Legislative and Regulatory Initiatives" in MD&A for additional information on specific CPUC proceedings . )

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn some additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs. (See "Results of Operations" in MD&A.) These mechanisms can also create financial risk. For a discussion of the re-opened proceeding to review incentive revenues awarded for the 2006-2008 energy efficiency cycle, see "Rehearing of CPUC Decisions Approving Energy Efficiency Incentive Awards" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below.

***Base Revenues***

*General Rate Cases*

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs, including return on rate base, related to its electricity distribution, natural gas distribution , and Utility owned electricity generation operations. The CPUC generally conducts a GRC every three years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases (known as "attrition rate adjustments") in revenue requirements for the subsequent years of the GRC period. Attrition rate adjustments are generally provided for cost increases related to increases in invested capital and inflation . Parties in the Utility's GRC include the ORA and TURN, who generally represent the overall interests of residential customers, as well as a myriad of other intervenors who represent residential and other customer interests.

For more information about the Utility's current GRC proceeding, see " Regulatory Matters −2017 General Rate Case" in MD&A.

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in the GT&S rate case. In its 2015 GT&S rate case, the Utility has request ed that the CPUC approve a total annual revenue requirement of $1.2 63 billion for the Utility's anticipated costs of providing natural gas transmission and storage services for 2 015. The Utility also requested revenue increases of $83 million in 2016 and $142 million in 2017. See " Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" in MD&A for additional information.

*Cost of Capital Proceedings*

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2017, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also set the authorized ROE at 10.40%. The CPUC also adopted an adjustment mechanism to allow the Utility's capital structure and ROE to be adjusted if the utility bond index changes by certain thresholds on an annual basis. During 2015, the adjustment mechanism was not triggered so the Utility's authorized ROE will remain at 10.40% for 2016. On February 12, 2016, a proposed decision was issued, that, if approved by the CPUC, will preclude the Utility from using the mechanism before its next cost of capital application. As a result, if the proposed decision is approved, the Utility's capital structure and ROE will not be adjusted for 2017. The CPUC will review the Utility's capital st ructure and ROE for 2018 in the Utility's next cost of capital proceeding. The Utility is required to file its 2018 cost of capital application by April 20, 2017 .

*Electricity Transmission Owner Rate Cases*

The FERC determines the amount of authorized revenue requirement s , including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The Utility generally files a TO rate case every year. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. These FERC-approved rates are included : 1) by the CPUC in the Utility's retail electric rates and are collected from retail electric customers ; and 2) by the CAISO in its Transmission Access Charges to wholesale customers . (See " Regulatory Matters – FERC TO Rate Cases" in MD&A.) The Utility also recovers a portion of its revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are charged individualized rates based on the terms of their contracts.

***Revenues to Recover Energy Procurement and Other Pass-Through Costs***

*Electricity Procurement Costs*

California investor-owned electric utilities are responsible for procuring electricity required to meet bundled customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electricity contracts. The utilities are responsible for scheduling and bidding electric generation resources, including electricity procured from third parties or the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their procurement plans based on long-term demand forecasts. T he CPUC has approved the Utility's procurement plan covering 2012 through 202 4 .

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved electricity procurement plans without further after-the-fact reasonableness review by the CPUC . The CPUC may disallow c osts associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to follow the principles of least-cost dispatch.

The Utility recovers its electricity procurement costs annually primarily through the energy resource recovery account . (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.) Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electricity rates more frequently if the forecasted aggregate over-collections or under-collections in the energy resource recovery account exceed 5% of its prior year electricity procurement and utility-owned generation revenues. The CPUC performs an annual compliance review of the transactions recorded in the energy resource recovery account.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, to meet mandatory renewable energy targets , and to comply with resource adequacy requirements. For additional information, s ee "Electric Utility Operations – Electricity Resources" below as well as Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

*Natural Gas Procurement and Transportation Costs*

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as “core” customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments through its retail gas rates that are subject to limits as set forth in its core procurement incentive mechanism, described below . The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rate change s. The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electricity rates.

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs. Under the core procurement incentive mechanism , the Utility’s natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers’ rates. One-half of the costs above 102% of the benchmark are recoverable in customers’ rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility’s cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by FERC-approved tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. The FERC approves the United States tariffs that shippers , including the Utility, pay for pipeline service , and the applicable Canadian tariffs are approved by the Alberta Utilities Commission and the National Energy Board. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as a cost of electricity.

*Costs Associated with Public Purpose and Customer Programs*

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide a discount rate for low-income customers, known as California Alternate Rates for Energy (“CARE”), which is subsidized by the Utility’s other customers.

*Nuclear Decommissioning Costs*

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Nuclear decommissioning costs are collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approval of the Utility’s updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility’s nuclear plants.

**Electric Utility Operations**

The Utility generates electricity and provides electricity transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides “bundled” services (i.e., electricity, transmission and distribution services) to most customers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations.

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of distributed energy resources. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. The CPUC also is considering the Utility's request for approval of the phased deployment of an electric vehicle charging infrastructure in response to the CPUC's December 2014 decision adopting a policy to expand the California utilities' role in developing an EV charging infrastructure to support California's climate goals. (For more information, see " Legislative and Regulatory Initiatives" in MD&A.)

***Electricity Resources***

The Utility is required to maintain generating capacity adequate to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule all of the electricity resources within its portfolio in the most cost-effective way **.**

The following table shows the percentage of the Utility's total deliveries of electricity to customers in 201 5 represented by each major electricity resource, and further discussed below.

Total 201 5 Actual Electricity Generated and Procured – 72,113 GWh [(1)] :

| | **Percent of Bundled Retail Sales** | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 22.6 % | |
| Small Hydroelectric | 0.7 % | |
| Large Hydroelectric | 4.6 % | |
| Fossil fuel-fired | 8.9 % | |
| Solar | 0.4 % | |
| Total | | 37.2 % |
| | | |
| Qualifying Facilities | | |
| Renewable | 3.0 % | |
| Non-Renewable | 6.5 % | |
| Total | | 9.5 % |
| Irrigation Districts and Water Agencies | | |
| Small Hydroelectric | 0.1 % | |
| Large Hydroelectric | 0.6 % | |
| Total | | 0.7 % |
| Other Third-Party Purchase Agreements | | |
| Renewable | 25.3 % | |
| Large Hydroelectric | 0.7 % | |
| Non-Renewable | 9.4 % | |
| Total | | 35.4 % |
| Others, Net [(2)] | | 17.2 % |
| **Total [(3)]** | | **100 %** |

[(1)] This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
[(2)] Mainly comprised of net CAISO open market purchases.
[(3)] Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by transmission and distribution related system losses.

*Renewable Energy Resources* . California law established a "renewable portfolio standard" (referred to as "RPS") that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers . I n October 2015, the California Governor signed SB 350 , the Clean Energy and Pollution Reduction Act of 2015 which, effective January 1, 2016, increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period and in each compliance period thereafter. SB 350 establishes increasing interim renewable energy targets for the periods between 2020 and 2030 but also provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets which the Utility expects will continue to be recoverable from customers as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC has stated its intent to propose a decision in late 2016 implementing SB 350's provisions requiring higher RPS targets and other changes made by the statute to the RPS rules.

Renewable generation resources, for purposes of the RPS requirements , include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. During 2015, 29.5 % of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 2 5 % of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (3. 0 %), the Utility's small hydroelectric facilities (0. 7 %), and the Utility's solar facilities (0. 4 %).

The total 2015 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales |
|---|---|---|
| Biopower | 3,141 | 4.4% |
| Geothermal | 3,664 | 5.0% |
| Wind | 5,451 | 7.6% |
| Solar | 8,157 | 11.3% |
| RPS-Eligible Hydroelectric | 878 | 1.2% |
| **Total** | **21,291** | **29.5%** |

*Energy Storage.* As required by California law, the CPUC has established initial energy storage procurement targets to be achieved by each load-serving entity, such as the Utility. The Utility must hold Requests for Offers (RFOs) to meet biennial targets and procure 580 MW of energy storage which must be operational by the end of 2024. The Utility's 2014-2015 energy storage procurement target was 80.5 MW. The Utility initiated its RFO on December 1, 2014 to obtain at least 74 MW o f transmission and distribution connected energy storage, signed contracts for 75 MW, and submitted those contracts for CPUC approval on the CP UC's December 1, 2015 deadline. The Utility met its remaining 6.5 MW customer-connected target by funding energy storage under the CPUC-mandated Self Generation Incentive Program. On January 1, 2016, the Utility reported its compliance with its 2014-2015 obligations to the CPUC. The Utility must file its 2016-2017 plan for procuring 120 MW of energy storage, consisting of 105 MW of transmission and distribution energy storage and 15 MW of customer-connected storage, by March 1, 2016. A CPUC decision on the Utility's plan is expected before the December 1, 2016 deadline for the Utility to issue its second energy storage RFO. The Utility continues to participate in the CPUC proceeding to refine California's energy storage program, which is considering potentially higher targets and expanded energy storage use cases.

*Owned Generation Facilities.* At December 31, 201 5 , the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---|---|---|---|
| Nuclear [1] : | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric [2] : | | | |
| Conventional | 16 counties in northern and central California | 104 | 2,684 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| Fuel Cell: | | | |
| CSU East Bay Fuel Cell | Alameda | 1 | 1 |
| SF State Fuel Cell | San Francisco | 2 | 2 |
| Photovoltaic [3]: | Various | 13 | 152 |
| **Total** | | **137** | **7,691** |

[1] The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses expire in 2024 and 2025, respectively. (See "Diablo Canyon Nuclear Power Plant " in . MD&A and Item 1A. Risk Factors.)
[2] The Utility's hydroelectric system consists of 107 generating units at 67 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years.
[3] The Utility's larger operational photovoltaic facilities include the Five Points solar station (15 MW), the Westside solar station (15 MW), the Stroud solar station (20 MW), the Huron solar station (20 MW), the Cantua solar station (20 MW), the Giffen solar station (10 MW), the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). All of these facilities are located in Fresno County, except for the Guernsey solar station, which is located in Kings County.

*Generation Resources from Third Parties.* The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. (See "Ratemaking Mechanisms" above.) For more information regarding the Utility's power purchase agreements, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.

***Electricity Transmission***

At December 31, 201 5 , the Utility owned approximately 18, 4 00 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also opera ted 91 electric transmission substations with a capacity of approximately 63,400 MVA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Co uncil, which includes many western states, Alberta and British Columbia, and parts of Mexico.

In 2013, the Utility, MidAmerican Transmission, LLC, and Citizens Energy Corporation were selected by the CAISO to jointly develop a new 230-kV transmission line to address the growing power demand in Fresno, Madera and Kings counties area. The 70-mile line will connect the Utility-owned and -operated Gates and Gregg substations. The new line will help reduce the number and duration of power outages, improve voltage in the area, support economic development, and bolster efforts to integrate clean, renewable energy onto the grid. The transmission line is expected to commence operations by 2022, and could come online earlier.

Throughout 201 5 , the Utility upgraded several critical substations and re-conductored a number of transmission lines to improve maintenance and system flexibility, reliability and safety. The Utility expects to undertake various additional transmission projects over the next several years to upgrade and expand the capacity of its transmission system to accommodate system load growth, secure access to renewable generation resources, replace aging or obsolete equipment and improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment.

***Electricity Distribution***

The Utility's electricity distribution network consists of a pproximately 142,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 58 transmission switching substations, and 603 distribution substations, with a capacity of approximately 31,400 MVA. The Utility's distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmissio n voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

These distribution substations serve as the central hubs for the Utility's electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. In 2015 the Utility commenced operations in a new electric distribution control center facilit y in Rocklin , California, and expects to complete an additional facility in Concord, California, in 2016. These control centers form a key part of the Utility's efforts to create a smarter, more resilient grid.

In 2015, the Utility continued to deploy its Fault Location, Isolation, and Service Restoration circuit technology which involves the rapid operation of s mart s witches to reduce the duration of customer outages. Another 83 circuits were outfitted with this equipment, bringing the total deployment to 700 of the Utility 's 3200 distribution circuits. The Utility also installed o r replaced 20 distribution substation transformer banks to improve reliability and provide capacity to accommodate growing demand. The Utility pl ans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2016 .

***Electricity Operating Statistics***

The following table shows certain of the Utility's operating statistics from 201 3 to 201 5 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 2015, 2014 and 2013.

| | | **2015** | | **2014** | | **2013** |
|---|---|---|---|---|---|---|
| Customers (average for the year) | | 5,311,178 | | 5,276,025 | | 5,243,216 |
| Deliveries (in GWh) [1] | | 85,860 | | 86,303 | | 86,513 |
| Revenues (in millions): | | | | | | |
| Residential | $ | 5,032 | $ | 4,784 | $ | 5,091 |
| Commercial | | 5,278 | | 5,141 | | 4,905 |
| Industrial | | 1,555 | | 1,543 | | 1,388 |
| Agricultural | | 1,233 | | 1,172 | | 1,021 |
| Public street and highway lighting | | 83 | | 79 | | 75 |
| Other [2] | | (84) | | (172) | | (128) |
| Subtotal | | 13,097 | | 12,547 | | 12,352 |
| Regulatory balancing accounts [3] | | 560 | | 1,109 | | 137 |
| **Total operating revenues** | **$** | **13,657** | **$** | **13,656** | **$** | **12,489** |
| Selected Statistics: | | | | | | |
| Average annual residential usage (kWh) | | 6,294 | | 6,458 | | 6,752 |
| Average billed revenues per kWh: | | | | | | |
| Residential | $ | 0.1719 | $ | 0.1603 | $ | 0.1643 |
| Commercial | | 0.1640 | | 0.1585 | | 0.1499 |
| Industrial | | 0.0973 | | 0.0998 | | 0.0928 |
| Agricultural | | 0.1610 | | 0.1516 | | 0.1454 |
| Net plant investment per customer | $ | 6,660 | $ | 6,339 | $ | 6,002 |

(1) These amounts include electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
(2) This activity is primarily related to a remittance of revenue to the Department of Water Resources ("DWR") (the Utility acts as a billing and collection agent on behalf of the DWR), partially offset by other miscellaneous revenue items.
(3) These amounts represent revenues authorized to be billed.

**Natural Gas Utility Operations**

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e. , natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as core transport agents). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more th an 91% o f core customers, representing n early 80% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers ( i.e ., outside of the Utility's service territory) and to third-party natural gas storage customers.

*Natural Gas Supplies*

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility also is supplied by natural gas fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated generally based on market conditions. During 201 5 , the Utility purchased appr oximately 307,100 MMcf o f natural gas (net of the sale of excess supply of gas). Substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 17 % of the total natural gas volume the Utility purchased during 201 5 .

*Natural Gas System Assets*

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 201 5 , the Utility's natural gas system consisted of approximately 42, 800 miles of distribution pipelines, over 6, 7 00 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport this gas from the U.S Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border, and firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport this natural gas from supply points in the U.S. Southwest to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas system in the area of Daggett, California. For more information regarding the Utility's natural gas transportation agreements, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's transmission system. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later withdrawal. In addition, four independent storage operators are interconnected to the Utility's northern California transmission system.

During 201 5 , the Utility conducted an annual system-wide review of its transmission pipeline class location designations . The Utility also continued work to install 217 automatic and remote control shut-off valves on its gas transmission system , as specified in the eleventh of twelve safety recommendations made by the NTSB following its investigation of the San Bruno accident. As of December 31, 2015, the Utility had installed 235 automatic and remote control shut-off valves , and the NTSB closed that recommendation . The final safety recommendation, considered open and acceptable by the NTSB, involves hydrostatic testing nearly 1,000 miles of the Utility's gas transmission system. The Utility has completed the majority of this task and currently plans to complete the task for the remaining approximately 100 of pipelines (involving primarily short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines) during 2018. Also, as part of the Utility's distribution integrity management program, the Utility completed approximately 23,500 sewer inspections during 2015 to identify and correct conflicts between gas and waste water facilities.

***Natural Gas Operating Statistics***

The following table shows the Utility's operating statistics from 201 3 through 201 5 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 2015, 2014 and 2013.

| | | **2015** | | **2014** | | **2013** |
|---|---|---|---|---|---|---|
| Customers (average for the year) | | 4,415,332 | | 4,394,283 | | 4,378,797 |
| Gas purchased (MMcf) | | 209,194 | | 202,215 | | 240,414 |
| Average price of natural gas purchased | $ | 2.11 | $ | 4.09 | $ | 3.29 |
| Bundled gas sales (MMcf): | | | | | | |
| Residential | | 144,885 | | 143,514 | | 181,775 |
| Commercial | | 43,888 | | 42,080 | | 46,668 |
| **Total Bundled Gas Sales** | | 188,773 | | 185,594 | | 228,443 |
| Revenues (in millions): | | | | | | |
| Bundled gas sales: | | | | | | |
| Residential | $ | 1,816 | $ | 1,683 | $ | 1,870 |
| Commercial | | 403 | | 419 | | 395 |
| Other | | 125 | | 51 | | 44 |
| Bundled gas revenues | | 2,344 | | 2,153 | | 2,309 |
| Transportation service only revenue | | 649 | | 662 | | 555 |
| Subtotal | | 2,993 | | 2,815 | | 2,864 |
| Regulatory balancing accounts | | 183 | | 617 | | 240 |
| **Total operating revenues** | $ | 3,176 | $ | 3,432 | $ | 3,104 |
| Selected Statistics: | | | | | | |
| Average annual residential usage (Mcf) | | 35 | | 34 | | 44 |
| Average billed bundled gas sales revenues per Mcf: | | | | | | |
| Residential | $ | 12.53 | $ | 11.72 | $ | 10.29 |
| Commercial | | 9.18 | | 9.96 | | 8.47 |
| Net plant investment per customer | $ | 2,573 | $ | 2,468 | $ | 2,234 |

**Competition**

***Competition in the Electricity Industry***

California law allows qualifying non-residential electric customers of investor-owned electric utilities to purchase electricity from energy service providers rather than from the utilities up to certain annual and overall GWh limits that have been specified for each utility. T his arrangement is known as "direct access." In addition, California law permits cities, counties, and certain other public agencies that have qualified to become a "community choice aggregator" (or "CCA") to generate and/or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from a utility.

The Utility continues to provide transmission, distribution, metering, and billing services to direct access customers, although these customers can choose to obtain metering and billing services from their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Utility is able to collect charges to recover the generation-related costs that the Utility incurred on behalf of direct access and CCA customers while they were the Utility's customers. The Utility remains the electricity provider of last r esort for these customers.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, may seek to acquire the Utility's distribution facilities, either under a consensual transaction or via eminent domain.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits at the full retail rate, are increasing.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission facilities within, or interconnected to, its service territory through a competitive bidding process managed by the CAISO.

***Competition in the Natural Gas Industry***

The Utility primarily competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

**Environmental Regulation**

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of carbon dio xide ($CO_2$) and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. (See Item 1A. Risk Factors.) Generally, the Utility recovers most of the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a special ratemaking mechanism described in Note 1 3 : Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in Item 8.

***Hazardous Waste Compliance and Remediation***

The Utility's facilities are subject to the requirements of the federal Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended. The Utility is also subject to the regulations adopted by the EPA, the federal agency responsible for implementing the federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act , these persons (known as "potentially responsible parties") may be jointly and severally liable for the costs of cleaning up the hazardous substances, paying for the harm caused to natural resources, and paying for the costs of required health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the California Department of Toxic Substances Control, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.

***Air Quality and Climate Change***

The Utility's electricity generation plants, natural gas pipeline operations, fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, $CO_2$, sulfur dioxide ($SO_2$), mono-nitrogen oxide ($NO_x$), particulate matter, and other GHG emissions.

In December 2009, the EPA concluded that GHG emissions contribute to climate change and issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. In May 2014, the U.S. Global Change Research Program (a confederation of the research arms of thirteen federal departments and agencies) released its third National Climate Assessment, which stated that the global climate is changing and that impacts related to climate change are already evident in many sectors and are expected to become increasingly disruptive across the nation throughout this century and beyond.

*Federal Regulation* . At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

In August 2015, the EPA published final regulations under section 111(b) of the Clean Air Act to control $CO_2$ emissions from new fo ssil fuel-fired power plants. While these regulations do not affect the Utility's existing power plants, the regulations impose emission limitations on fossil fuel-fired power plants constructed after January 8, 2014 and will affect the design, construction, operation and cost of such power plants.

I n August 2015 , the EPA also published final regulations under section 111(d) of the Clean Air Act to control $CO_2$ emissions from existing fossil fuel-fired power plants . These regulations are designed to reduce power plant $CO_2$ em issions on a national basis by as much as 32% by 2030, compared with 2005 levels. States must submit final plans to comply with the se regulations by September 2016, but may request an extension to file such plans until September 2018. It is uncertain whether and how these federal regulations will ultimately impact California, since existing state regulation currently requires, among other things, the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. Following publication of the EPA's regulations , in October 2015 West Virginia and several other states and parties challenged the EPA's section 111(d) regulations in the United States Court of Appeals for the District of Columbia Circuit and petitioned the Court to stay the regulations pending review of the appeal on the merits. The D.C. Circuit denied the request for stay but in February 2016, the United States Supreme Court granted a stay of the section 111(d) regulations pending review of the appeal by the D.C. Circuit. The Supreme Court's decision may affect the nature, extent and timing of implementat ion of these regulations. As described below, the Utility expects all costs and revenues associated with the state-wide, comprehensive cap-and-trade program to be passed through to customers.

*State Regulation.* California 's AB 32, the Global Warming Solutions Act of 2006, provides for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target , including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy. The cap - and-trade program's first compliance period, which began on January 1, 2013, applied to the electricity generation and large industrial sectors. The next compliance period, which began on January 1, 2015, expanded to include the natural gas and transportation sectors, effectively covering all the economy's major sectors until 2020. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Emitters may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owners, and farmers) that occur outside of the emitters' facilities through CARB-qualified offset projects such as reforestation or biomass projects. During 2016, CARB and the California Legislature are likely to consider proposals to achieve additional GHG reductions beyond the 2020 target established in AB 32. The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers. The California RPS program that requires the utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California.

*Climate Change Mitigation and Adaptation Strategies.* During 201 5 , the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to plan for the actions that it will need to take to adapt to the likely impacts of climate change on the Utility's future operations. The Utility regularly reviews the most relevant scientific literature on climate change such as sea level rise, temperature changes, rainfall and runoff patterns, and wildfire risk, to help the Utility identify and evaluate climate change-related risks and develop the necessary adaptation strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including extreme storms, heat waves and wildfires and uses its risk-assessment process to prioritize infrastructure investments for longer-term risks associated with climate change. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme, persistent, and frequent hot weather. The Utility believes its str ategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of rene wable energy and energy storage are effective strategies for adapting to the expected increase in demand for electricity. The Utility is making substantial investments to build a more modern and resilient system that can better withstand extreme weather and related emergencies. The Utility's vegetation management activities also reduce the risk of wildfire impacts on electric and gas facilities. Over the long-term, the Utility also faces the risk of higher flooding and inundation potential at coastal and low elevation facilities due to sea level rise combined with high tides, storm runoff and storm surges.

Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. This could, in turn, affect the Utility's hydroelectric generation. To plan for this potential change, the Utility is engaging with state and local stakeholders and is also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and collaborating on research and new modeling tools.

With respect to natural gas operations, both safety-related pipeline strength testing and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and volume of natural gas within pipelines prior to venting. In addition, the Utility continues to achieve reductions in methane emissions by implementing improvements in leak detection and repair, upgrades at metering and regulating stations, and maintenance and replacement of other pipeline materials.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-pro fit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2014 totaled more than 58 milli on metric tonnes of $CO_2$ equivalent , nearly two-thirds of which came from customer natural gas use. The following table shows the 201 4 GHG emissions data the Utility reported to the CARB under AB 32 . PG&E Corporation and the Utility publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| **Source** | **Amount (metric tonnes $CO_2$ equivalent)** |
|---|---|
| Fossil Fuel-Fired Plants [1] | 2,407,734 |
| Natural Gas Compressor Stations and Storage Facilities [2] | 348,155 |
| Distribution Fugitive Natural Gas Emissions | 750,223 |
| Customer Natural Gas Use [3] | 41,616,935 |

[1] Includes nitrous oxide and methane emissions from the Utility's generating stations.
[2] Includes compressor stations and storage facilities emitting more than 25,000 metric tonnes of $CO_2$ equivalent annually.
[3] Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural gas local distribution companies. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities , as calculated by the CARB .

The following table shows the Utility's third-party-verified $CO_2$ emissions rate associated with the electricity delivered to customers in 201 4 as compared to the national average for electric utilities:

| | **Amount (pounds of $CO_2$ per MWh)** |
|---|---|
| U.S. Average [1] | 1,137 |
| Pacific Gas and Electric Company [2] | 435 |

[1] Source: EPA eGRID.
[2] Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's emissions rate.

***Air Emissions Data for Utility-Owned Generation***

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised approximately 36 % of the Utility's delivered electricity in 201 4 . PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | **2014** | **2013** |
|---|---|---|
| Total NOx Emissions (tons) | 141 | 153 |
| NOx Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total $SO_2$ Emissions (tons) | 14 | 17 |
| $SO_2$ Emissions Rate (pounds/MWh) | 0.0010 | 0.0011 |

***Water Quality***

On May 19, 2014, the EPA issued final regulations to implement the requirements of the federal Clean Water Act that require cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. Various industry and environmental groups have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Fourth Circuit. California's once-through cooling policy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, in 2010 the California Water Board adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. As required by the policy the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014 and the board is not expected to issue a final decision regarding Diablo Canyon's compliance with the state policy before January 2017 . If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

The final requirements of the federal and state cooling water policies could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (See "Diablo Canyon Power Plant" in Item 3. Legal Proceedings below.)

***Nuclear Fuel Disposal***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. The settlement agreement also provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. In 2015 , the Utility was awarded an additional $ 21 million for costs incurred between June 1, 2013 and May 31, 2014 . The claim for the period June 1, 2014 through May 31, 2015 is under review by the DOE. These proceeds are being refunded to customers through rates. The settlement agreement, as amended, does not address costs incurred for spent fuel storage beyond 2016 and such costs could be subject to future litigation. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

## ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results can be affected by many factors , including estimates and assumptions used in the critical accounting policies described in MD&A, that can cause their actual financial results to differ materially from historical results or from anticipated future financial results . T he following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with MD&A and the consolidated financial statements and related notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this Form 10-K . Any of these factors , in whole or in part, could materially affect PG&E Corporation's and the Utility's business, results of operations , financial condition, a nd stock price.

### Risks Related to the Outcome of Enforcement Matters, Investigations, and Regulatory Proceedings

***PG&E Corporation's and the Utility's future financial results may be materially affected by the outcome of the federal criminal prosecution of the Utility.***

As discussed in MD&A, the Utility is facing federal criminal charges alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act and alleging t hat the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident that occurred on September 9, 2010 . The maximum statutory fine for each felony count is $500,000, for potential total fines of $ 6.5 million. The federal prosecutor also seeks to impose an alternative fine which could total approximately $ 562 m illion , b ased on allegations that the Utility derived gross gains of approximately $281 million . The trial currently is scheduled to begin on March 22 , 2016.

PG&E Corporation and the Utility have not recorded any charges for potential criminal fines in their consolidated f inancial statements at December 31, 2015. If the Utility is convicted and a fine is imposed, PG&E Corporation and the Utility will record charges when required in accordance with GAAP. The Utility also could incur material costs, not recoverable through rates, to implement remedial measures that may be imposed by the court, such as a requirement that the Utility's natural gas operations be supervised by a third-party monitor . The Utility could also be suspended or debarred from entering into federal procurement and non-procurement contracts and programs.

If the Utility incurred material fines or costs following a conviction, PG&E Corporation may need to issue common stock to raise funds to contribute to the Utility to maintain the required equity component of the Utility's authorized capital structure as the Utility incur charges and costs. These issuances would be incremental to PG&E Corporation's current forecast of common stock issuances and could materially dilute PG&E Corporation's EPS. The trial and any negative publicity associated with it, as well as the Utility's conviction and the imposition of a material fine, if incurred, also could affect the Utility's and PG&E Corporation's credit ratings or outlooks and make it more difficult for PG&E Corporation and the Utility to access the capital markets.

The trial and the Utility's conviction could harm the Utility's relationships with regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, they could negatively affect the outcome of future ratemaking and regulatory proceedings ; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the criminal charges .

In addition, the Utility's conviction could result in increased regulatory or legislative pressure to require the separation of the Utility's electric and natural gas businesses, restructure the corporate relationship between PG&E Corporation and the Utility, or undergo some other fundamental corporate restructuring. As discussed under the heading "Regulatory Matters" in MD&A, the SED will evaluate PG&E Corporation's and the Utility's organizational structure in the CPUC's pending investigation to examine the Utility's safety culture.

***PG&E Corporation's and the Utility's future financial results may be materially affected by the outcome s of the CPUC's investigative enforcement proceedings against the Utility, other known enforcement matters, and other ongoing state and federal investigations. The Utility also could incur material costs and fines in connection with future investigations, citations, audits, or enforcement actions.***

The Utility could incur material charges, including fines and other penalties, in connection with the CPUC's investigation s of the Utility's compliance with natural gas distribution record-keeping practices and th e Utility's compliance with the CPUC's rules regarding ex parte communications . In addition, there are several other investigations by f ederal and state law enforcement authorities . The Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. Federal and state law enforcement authorities also have been investigating matters related to allegedly improper communication between the Utility and CPUC personnel. If these investigations result in enforcement action against the Utility, the Utility could incur additional fines or penalties or suffer negative consequences described above in the immediately preceding risk factor . In addition , a negative outcome in any of these investigations or future enforcement actions may negatively affe c t the outcom e of fut u re rat e making and regul a to ry proceeding s; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations.

The SED also could impose material fines on the Utility based on the Utility's self-reports submitted in accordance with the SED's safety citation program and the Utility's efforts to identify and remove encroachments from transmission pipeline rights of way. The Penalty Decision r equires the SED to review the Utility's gas transmission operations (including t he Utility's compliance with the remedies ordered by the Penalty Decision) and to perform annual audits of the Utility's record-keeping practices for a minimum of ten years. T he SED could impose f ines on the Utility or require the Utility to incur unrecoverable costs, or both, based on the outcome of the se future audits . In addition, although PG&E Corporation and the Utility do not currently face the possibility of fines or penalties in the first phase of the CPUC's pending investigation into the Utility's safety culture since it has been categorized as rate setting, it is uncertain how the next phase will be categorized. (See the discussion under the heading "Regulatory Matters" in MD&A.)

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and resource adequacy requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; and federal electric reliability standards . The SED could impose fines on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds could have a material effect on PG&E Corporation's and the Utility's financial results.

***PG&E Corporation's and the Utility's future financial results could be materially affected by the extent to which its natural gas transmission costs exceed authorized revenues as the Utility complies with the Penalty Decision a nd incurs other natural gas transmission costs that are unrecoverable or that the Utility has not sought to recover.***

The Utility's ability to recover its natural gas transmission and storage costs and earn its authorized ROE could be materially affected by the amount of revenues the CPUC ultimately authorizes the Utility to collect in the 2015 GT&S rate case proceeding and future GT&S rate cases. (See "R egulatory Matters " in Item 7. MD&A.) The Utility continues to incur material unrecoverable costs to meet the Penalty Decision's requirement to fund safety-related projects and programs to be identified by the CPUC in the 2015 GT&S rate case. Depending on how the CPUC designates pipeline safety-related projects and programs the Utility is required to fund, and how the Utility's associated costs are counted toward meeting the $850 million maximum disallowance imposed by the Penalty Decision , the ultimate amount of unrecoverable pipeline-related costs the Utility incurs may be higher than current forecasts. In addition, the Penalty Decision requires the Utility to implement various remedial measures which the CPUC estimated would cost $50 million. Actual costs to implement the remedies could be higher.

In addition, the Utility plans to incur unrecoverable costs to continue performing certain work to complete projects under the PSEP and to identify and remove encroachments from gas transmission pipeline rights-of-way. Actual costs to perform this work could exceed forecasts .

***PG&E Corporation's and the Utility's financial results primarily depend on the outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its operating expenses and capital expenditures so that it is able to earn its authorized rate of return in a timely manner.***

As a regulated entity, the Utility's rates are set by the CPUC or the FERC on a prospective basis and are generally designed to allow the Utility to collect sufficient revenues to recover the costs of providing service, including a return on its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the Utility's reputation (especially if the Utility is convicted of the federal criminal charges discussed above), the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and afford able electric and gas services.

The Utility also is required to incur costs to comply with legislative and regulatory requirements and initiatives, such as those relating to the development of a state-wide electric vehicle charging infrastructure, the deployment of distributed energy resources, implementation of demand response and customer energy efficiency programs, energy storage and renewable energy targets, and the construction of the California high-speed rail project. The Utility's ability to recover costs , including its investment s , associated with these and other legislative and regulatory initiatives will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service s .

In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial results could be materially affected if the Utility's actual costs to safely and reliably serve its customers differ from authorized or forecast costs. The Utility may incur additional costs for many reasons including changing market circumstances, unanticipated events (such as storms, accidents, catastrophic or other events affecting the Utility's operations), or compliance with new state laws or policies. Although the Utility may be allowed to recover some or all of the additional costs, there may be a substantial time lag between when the Utility incurs the costs and when the Utility is authorized to collect revenues to recover such costs. Alternatively, the CPUC or the FERC may disallow costs that they determine were not reasonably or prudently incurred by the Utility.

The Utility's ability to recover its costs also may be affected by the economy and its impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers or the level of uncollectible bills could increase. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base.

Changes in commodity prices also may have an adverse effect on the Utility's ability to timely recover its operating costs and earn its authorized ROE. Although the Utility generally recovers its electricity and natural gas procurement costs from customers as "pass-through" costs, a significant and sustained rise in commodity prices could create overall rate pressures that make it more difficult for the Utility to recover its costs that are not categorized as "pass-through" costs. To relieve some of this upward rate pressure, the CPUC could authorize lower revenues than the Utility requested or disallow full cost recovery.

***PG&E Corporation's and the Utility's financial results depend upon the Utility's continuing ability to recover "pass-through" costs, including electricity and natural gas procurement costs, from customers in a timely manner. The CPUC may disallow procurement costs for a variety of reasons. In addition, the Utility's ability to recover these costs could be affected by the loss of Utility customers and decreased new customer growth , if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch" and prudent administration of power purchase agreements in compliance with its CPUC-approved long-term procurement plan. The CPUC could disallow procurement costs incurred by the Utility if the CPUC determines that the Utility did not comply with these principles or if the Utility did not comply with its procurement plan.

Further, the contractual prices for electricity under the Utility's current or future power purchase agreements could become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to adverse economic conditions or the loss of the Utility's customers to other retail providers. In particular, the Utility will incur additional costs to procure renewable energy to meet the higher targets established by California SB 350 that became effective on January 1, 2016. Despite the CPUC 's current approval of the contracts, the CPUC could disallow contract costs in the future if it determines that the costs are unreasonably above market.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by the whether the CAISO wholesale electricity market continues to function effectively. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended which could result in excessive market prices. The CPUC could prohibit the Utility from passing through the higher costs of electricity to customers. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's then-newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth that occurs through municipalization of the Utility's facilities, an increase in the number of CCAs who provide electricity to their residents, and an increase in the number of consumers who become direct access customers of alternative generation providers. (See "Competition in the Electric ity Industry" in Item 1.) As the number of bundled customers (i.e., those primarily residential customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase as the Utility would have a smaller customer base from which to recover certain procurement costs. Although the Utility is permitted to collect non-bypassable charges for generation-related costs incurred on behalf of former customers, the charges may not be sufficient for the Utility to fully recover the se costs. In addition, the Utility's ability to collect non-bypassable charges has been, and may continue to be, challenged by certain customer groups. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering ("NEM"), which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pressure on remaining customers. In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates are expected t o become effective for new NEM customers of the Utility later in 2016. New NEM customers will be required to pay an interconnection fee, will go on time of use rates, and will be required to pay some non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. However, the resulting rules will still put upward rate pressure on remaining customers, and remove the cap on the number of NEM customers. Significantly higher rates for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers. The CPUC states that it intends to revisit these rules in 2019.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments. If the number of the Utility's customers decreases or grows at a slower rate than anticipated, the Utility's level of capital investment would likely decline as well, in turn leading to a slower growth in rate base and earnings. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could adversely impact PG&E Corporation's and the Utility's financial results.

The CPUC has begun to implement rate reform to allow residential electric rates to more closely reflect the utilities' actual costs of providing service and decrease cost-subsidization among customer classes. Many aspects of rate reform are not yet finalized, including time-of-use rates and whether the utilities can impose a fixed charge on certain customers. I f the Utility is unable to recover a material portion of its procurement costs and/or if the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, the wide deployment of distributed generation, and the development of new electricity generation and energy storage technologies , PG&E Corporation's and the Utility's financial results could be materially affected .

**Risks Related to Liquidity and Capital Requirements**

***PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.***

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, pay fines that may be imposed in the future, and incur costs to meet the Penalty Decision's requirement to incur costs of up to $850 million for safety-related projects and programs to be identified by the CPUC in the 2015 GT&S rate case. PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation's and the Utility's credit ratings and outlook. Their credit ratings and outlook can be affected by man y factors, including the outcome s of the on-going criminal prosecution, the pending CPUC investigations, and ratemaking proceedings. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced , or lack of, access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, volatility in electricity or natural gas prices, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under "Enforcement and Litigation Matters" in Item 7. MD&A. The negative publicity and the uncertainty about the outcomes of these matters may undermine investors' confidence in management's ability to execute its business strategy and restore a constructive regulatory environment. As a result, investors may be less willing to buy shares of PG&E Corporation common stock resulting in a lower stock price. Further, the market price of PG&E Corporation common stock could decline materially after the outcomes are determined. The amount and timing of future share issuances also could affect the stock price.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation and PG&E Corporation could be required to contribute capital to the Utility to enable the Utility to fulfill its obligation to serve. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

***PG&E Corporation's ability to meet its debt service and other financial obligations and to pay dividends on its common stock depends on the Utility's earnings and cash flows.***

PG&E Corporation is a holding company with no revenue generating operations of its own. The Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. Under the CPUC's rules applicable to utility holding companies, the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company and PG&E Corporation's Board of Directors give "first priority" to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC has interpreted this "first priority" obligation to include the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." I n addition, before the Utility can pay common stock dividends to PG&E Corporation, the Utility must maintain its authorized capital structure with an average 52% equity component.

If the Utility were required to pay a material amount of fines or incur material unrecoverable costs due to a conviction in the on-going criminal prosecution, the pending CPUC investigations , or other enforcement matters , it would require equity contributions from PG&E Corporation to restore its capital structure. PG&E Corporation common stock issuances used to fund such equity contributions could materially dilute EPS . (See "Liquidity and Financial Resources" in Item 7. MD&A.) Further, if PG&E Corporation were required to infuse the Utility with significant capital or if the Utility was unable to distribute cash to PG&E Corporation, or both, PG&E Corporation may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend , or meet other obligations.

PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated ca pitalization of at most 65%.

**Risks Related to Operations and Information Technology**

***The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial results . T he Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system . (See " Electric Utility Operations " and " Natural Gas Utility Operations " in Item 1. Business.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives. The Utility's ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond the Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;

- an overpressure event occurring on natural gas facilities due to e quipment f ailure , i ncorrect o peratin g procedures or failure to follow correct operating procedure s , or we lding or f abrication- r elated d efect s, that results in the failure of downstream transmi ssion pipelines or distribution assets and uncontained natural gas flow;
- f ailure to maintain adequate capacity to meet customer demand on the gas system that result s in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electrical black-out that result s in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees or the public, environment al damage , or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act ;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wild land fire or natural gas explosion) , and the failure to respond effectively to a catastrophic event;
- inadequate emergency preparedness plans and the failure to r espo nd effectively to a catastrophic event that can lead to public or employee harm or exte nded outages;
- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wild land and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;
- operator or other human error;
- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudent ly;
- construc tion performed by third parties that damage the Utility's underground or overhead facilities , including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines ;
- the release of hazardous or toxic substances into the air, water , or soil, including, for example, gas leaks from natural gas storage facilities ; flaking lead paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and
- attacks by third parties, including cyber-attacks , acts of terrorism, vandalism, or war .

The occurrence of any of these events could interrupt fuel supplies; affect demand for electricity or natural gas; cause unplanned outages or reduce generating output; damage the Utility's assets or operations; damage the assets or operations of third parties on which the Utility relies; damage property owned by customers or others; and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, and to compensate third parties . In particula r, the Utility may incur material liability in connection with a wildfire (known as the "Butte fire") that ignited and spread in Amador and Calaveras c ounties i n Northern California in September 2015 depending on the outcome of the investigations into the cause of the fire . If insurance recoveries are unavailable or insufficient to cover such costs , PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected. The Utility also could incur material fines, penalties or disallowances , as a result of enforcement actions taken by the CPUC or other law enforcement agencies .

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities or the construction or demolition or facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions. Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial results. Future insurance coverage may not be available at rates and on terms as favorable as the Utility's current insurance coverage or may not be available at all.

***The Utility's operational and information technology systems could fail to function properly or be damaged by third parties (including cyber-attacks and acts of terrorism), severe weather, natural disasters, or other events. Any of these events could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense or liability to third parties.***

The operation of the Utility's extensive electricity and natural gas systems rel ies on evolving and increasingly complex operational and information technology systems and network infrastructures that are interconnected with the systems and network infrastructure owned by third parties. The Utility's business is highly dependent on its ability to process and monitor, on a daily basis, a very large number of tasks and transactions . Despite implementation of security measures, all of the Utility's technology systems are vulnerable to disability or failures due to hacking, viruses, acts of war or terrorism and other causes. The failure of the Utility's operational and information technology systems and networks could significantly disrupt operations; cause harm to the public or employees; result in outages or reduced generating output; damage the Utility's assets or operations or those of third parties; and subject the Utility to claims by customers or third parties, any of which could have a material effect on PG&E Corporation's and the Utility's financial results.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require ongoing maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. The Utility often relies on third-party vendors to maintain, modify, and update its systems and these third-party vendors could cease to exist. Any disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification or implementation of new systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively affect the Utility's ability to maintain effective financial control s , and/or the Utility's ability to timely file required regulatory reports. The Utility also could be subject to patent infringement claims arising from the use of third-party technology by the Utility or by a third-party vendor.

In addition, the Utility's information systems contain confidential information, including information about customers and employees. The theft, damage, or improper disclosure of confidential information can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, reduce the value of proprietary information, and harm the Utility's reputation.

***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire .***

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial results. In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.)

In addition, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power . Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation . As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before the licenses expire in 2024 and 2025 . In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial result s.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See "Regulatory Environment" in Item 1. Business.) If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon before the licenses expire in 2024 and 2025. At December 31, 2015, the Utility's unrecovered investment in Diablo Canyon was $2.3 billion.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects.

Further, the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon expire in 2018 and 2019. The Utility has requested that the California State Lands Commission renew the leases until 2024 and 2025 when the NRC licenses expire. The California State Lands Commission has deferred acting on the application until later in 2016. It is uncertain what level of environmental review, if any, will be required before the leases can be extended. If the leases are not extended or if the Utility determines that it cannot comply with any new environmental conditions in a feasible and economic manner, then operations at Diablo Canyon would cease and the Utility could incur a material charge for the remaining amount of its unrecovered investment.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial results could be materially affected.

**Risks Related to Environmental Factors**

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial results.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 for more information.)

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance . (See "Environmental Regulation" in Item 1.) The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial results. Their financial results also can be materially affected by changes in estimated costs and by the extent to which actual remediation costs differ from recorded liabilities.

***The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.***

The Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns , rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. Increasing temperatu res and changing levels of precipitation in the Utility's service territory would reduce snowpack in the Sierra Mountains. If the levels of snowpack were reduced, the Utility's hydroelectric generation would decrease and the Utility would need to acquire additional generation from other sources at a greater cost. If the Utility increase s its reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, increasing temperatures and lower levels of precipitation could increase the occurrence of wildfires in the Utility's service territory causing damage to the Utility's facilities or the facilities of third parties on which the Utility relies to provide service , damage to third parties for loss of property, personal injury, or loss of life . In addition, flooding caused by rising sea levels could damage the Utility's facilities, including hydroelectric assets such as dams and canals, and the electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

**Other Risk Factors**

***The Utility may be required to incur substantial costs in order to obtain or renew licenses and permits needed to operate the Utility's business and the Utility may be subject to fines and penalties for failure to comply or obtain license renewal.***

The Utility must comply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility's hydroelectric generation facilities, and those issued by environmental and other federal, state and local governmental agencies. Many of the Utility's capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizations, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility. If a license or permit is not renewed for a particular facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs. Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Utility's compliance costs. In particular, in connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility. In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has not been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, licenses, ordinances, or other requirements, or if the Utility cannot recover the increase in associated compliance and other costs in a timely manner, PG&E Corporation's and the Utility's financial results could be materially affected.

***Poor investment performance or other factors could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. The performance of the debt and equity markets affects the value of plan assets and trust assets. A decline in the market value may increase the funding requirements for these plans and trusts. The cost of providing pension and other postretirement benefits is also affected by other factors, including interest rates used to measure the required minimum funding levels, the rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by the rates of return on trust assets, changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. (See Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in Item 8.) If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans or if actual nuclear decommissioning costs exceed the amount of nuclear decommissioning trust funds and the Utility is unable to recover the contributions or additional costs in rates, PG&E Corporation's and the Utility's financial results could be materially affected .

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility's workforce is aging and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements with the unions or if tentative new agreements are not ratified by their members . In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceedings. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. P ROPERTIES

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under "Electric Utility Operations" and "Natural Gas Utility Operations." The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11.1 million square feet of real property, including 8.9 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire in 2022.

The Utility currently owns approximately 168,000 acres of land, including approximately 140,000 acres of watershed lands. In 2002 the Utility agreed to implement its "Land Conservation Commitment" ("LCC") to permanently preserve the six "beneficial public values" on all the watershed lands through conservation easements or equivalent protections, as well as to make approximately 70,000 acres of the watershed lands available for donation to qualified organizations. The six "beneficial public values" being preserved by the LCC include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Utility's goal is to implement all the transactions needed to implement the LCC by the end of 2018, subject to securing all required regulatory approvals.

## ITEM 3. L EGAL PROCEEDINGS

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

### Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission

On April 9, 2015, the CPUC approved final decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record-keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record-keeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010 . A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. In August 2015, the Utility paid the $300 million fine. At December 31, 2015, the Consolidated Balance Sheets include $400 million in current liabilities – other for the one-time bill credit that will be provided to the Utility's natural gas customers in 2016. On January 14, 2016, the CPUC issued final decisions to close these investigative proceedings.

The Penalty Decision requires that at least $689 million of the $850 million disallowance be allocated to capital expenditures, and that the Utility be precluded from including these capital costs in rate base. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the 2015 GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent. The CPUC is expected to issue a final decision in the Utility's 2015 GT&S rate case in 2016 to identify safety-related projects and programs that will be subject to the disallowance. It is uncertain how much of the Utility's costs to perform the safety-related projects and programs the CPUC will identify as counting toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. As a result, the total shareholder-funded obligation could exceed $850 million. For more information, see "Enforcement and Litigation Matters" in Note 13: Contingencies and Commitments of the Notes to the Consolidated Financial Statements in Item 8 .

**Federal Criminal Indictment**

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that superseded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. The maximum statutory fine for each felony count is $500,000 for total potential fines of $6.5 million. On December 8, 2015, the court also issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act. ( The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." ) The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of the gross gain prior to deciding whether to dismiss those allegations . ( Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million. ) After considering the additional information submitted by the government, on February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges. The trial on the criminal charges currently is scheduled to begin March 22, 2016.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Consolidated Financial Statements as such amounts are not considered to be probable.

**Litigation Related to the San Bruno Accident and Natural Gas Spending**

As of December 31, 2015, there were six purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the *San Bruno Fire Derivative Cases* and are pending in the Superior Court of California, County of San Mateo. On August 28, 2015, the Superior Court overruled the demurrers filed by PG&E Corporation, the Utility and the individual director and officer defendants seeking to dismiss the *San Bruno Fire Derivative Cases* , based upon the plaintiffs' failure to demand action by the Boards of PG&E Corporation and the Utility prior to filing the complaint. After the ruling, and pursuant to co-petitions for writ of mandate previously filed by PG&E Corporation, the Utility, and the individual defendants, on September 3, 2015, the California Court of Appeal issued an order staying the *San Bruno Fire Derivative Cases* pending the court's final determination whether to stay the matter altogether until the resolution of federal criminal proceedings against the Utility. On September 30, 2015, PG&E Corporation, the Utility, and the individual defendants filed an additional petition for writ of mandate asking the Court of Appeal to review the lower court's August 28 decision overruling their demurrers. On October 22, 2015, the Court of Appeal issued a ruling declining to review the August 28 decision. On December 8, 2015, the Court of Appeal issued a writ of mandate to the Superior Court, ordering the Superior Court to stay all proceedings in the *San Bruno Fire Derivative Cases* "pending conclusion of the federal criminal proceedings" against the Utility. The other two derivative actions are entitled *Tellardin v. PG&E Corp. et. al.* , pending in the Superior Court of California, San Mateo County, and *Iron Workers Mid-South Pension Fund v. Johns, et. al* ., pending in the United States District Court for the Northern District of California. PG&E Corporation, and the other defendants have not answered or otherwise responded to the complaints in these actions. In the *Tellardin* action, the defendants must answer or respond to the complaint 30 days after the stay in the *San Bruno Fire Derivative Cases* is lifted. In the *Iron Workers* action, the court has not established a deadline by which the defendants must an swer or respond. Case management conferences have been scheduled in both actions (March 21, 2016 in the *Tellardin* action and June 3, 2016 in the *Iron Workers* action), after which PG&E Corporation will have more information about any further proceedings in these actions.

**Investigation of the Butte Fire**

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. The California Department of Forestry and Fire Protection ("Cal Fire") is investigating the source of the Butte Fire to determine whether a tree contacted a power line operated by the Utility and was the cause of the fire. Cal Fire has reported that as a result of the fire there were two deaths and 965 structures, including 571 houses, were damaged or destroyed. Cal Fire's investigation is expected to conclude in 2016.

Approximately 27 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving more than 600 individual plaintiffs and their insurance companies. Plaintiffs and the Utility filed petitions with the California Judicial Council to coordinate these cases. The petitions were assigned to the Calaveras Superior Court for a recommendation to the Judicial Council. On January 21, 2016, the Calaveras Superior Court issued an order recommending to the Judicial Council that the cases be coordinated in the Superior Court of California, Sacramento County, for all purposes including trial. Among other factors, the Court found that coordination requires a court with a significant number of judges and complex litigation support personnel, neither of which are present in Calaveras County. For additional information, see "Enforcement and Litigation Matters" in Note 13: Contingencies and Commitments of the Notes to the Consolidated Financial Statements in Item 8.

**Other Enforcement Matters**

The Utility also could be required to pay fines, or incur other unrecoverable costs, associated with the CPUC's pending investigations of the Utility's natural gas distribution facilities record-keeping practices and the Utility's potential violations of the CPUC's ex parte communication rules. In addition, fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with natural gas safety regulations, investigations that were commenced after a pipeline explosion in Carmel, California on March 3, 2014, and other enforcement matters. See "Enforcement and Litigation Matters" in Note 13: Contingencies and Commitments of the Notes to the Consolidated Financial Statements in Item 8.

**Diablo Canyon Power Plant**

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

The final requirements of the federal and state cooling water policies (discussed above in Item 1. Business under “Environmental Regulation – Water Quality”) could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on the Utility’s financial condition or results of operations.

**Venting Incidents in San Benito County**

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called “pigs” that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline is released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility’s transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County District Attorney notified the Utility in December 2014 that it was contemplating bringing legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. The Utility has been in settlement discussions with the district attorney’s office since that time. On October 28, 2015, the district attorney informed the Utility that it would seek civil penalties in excess of $100,000 but is willing to continue to explore settlement options with the Utility.

**ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

**EXECUTIVE OFFICERS OF THE REGISTRANTS**

The following individuals serve as executive officers (1) of PG&E Corporation and/or the Utility, as of February 18, 2016. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| Anthony F. Earley, Jr. | 66 | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation | September 13, 2011 to present |
| | | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| Nickolas Stavropoulos | 57 | President, Gas | September 15, 2015 to present |
| | | President, Gas Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Gas Operations | June 13, 2011 to August 16, 2015 |
| | | Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid | August 2007 to March 31, 2011 |
| Geisha J. Williams | 54 | President, Electric | September 15, 2015 to present |
| | | President, Electric Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Electric Operations | June 1, 2011 to August 16, 2015 |
| | | Senior Vice President, Energy Delivery | December 1, 2007 to May 31, 2011 |
| Jason P. Wells | 38 | Senior Vice President and Chief Financial Officer, PG&E Corporation | January 1, 2016 to present |
| | | Vice President, Business Finance | August 1, 2013 to December 31, 2015 |
| | | Vice President, Finance | October 1, 2011 to July 31, 2013 |
| | | Senior Director and Assistant Controller | November 1, 2008 to September 30, 2011 |
| Dinyar B. Mistry | 54 | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to present |
| | | Vice President and Controller, PG&E Corporation | March 8, 2010 to present |
| | | Vice President and Controller | March 8, 2010 to September 30, 2011 |
| John R. Simon | 51 | Executive Vice President, Corporate Services and Human Resources, PG&E Corporation | August 17, 2015 to present |
| | | Senior Vice President, Human Resources | April 16, 2007 to August 16, 2015 |
| | | Senior Vice President, Human Resources, PG&E Corporation | April 16, 2007 to August 16, 2015 |
| Karen A. Austin | 54 | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| | | President, Consumer Electronics, Sears Holdings | February 2009 to May 2011 |
| Desmond A. Bell | 53 | Senior Vice President, Safety and Shared Services | January 1, 2012 to present |
| | | Senior Vice President, Shared Services and Chief Procurement Officer | October 1, 2008 to December 31, 2011 |

| | | | |
|---|---|---|---|
| Helen A. Burt | 59 | Senior Vice President, External Affairs and Public Policy, PG&E Corporation | September 30, 2015 to present |
| | | Senior Vice President, Corporate Affairs | September 18, 2014 to September 30, 2015 |
| | | Senior Vice President, Corporate Affairs, PG&E Corporation | September 18, 2014 to September 30, 2015 |
| | | Senior Vice President and Chief Customer Officer | February 27, 2006 to September 17, 2014 |
| Loraine M. Giammona | 48 | Senior Vice President and Chief Customer Officer | September 18, 2014 to present |
| | | Vice President, Customer Service | January 23, 2012 to September 17, 2014 |
| | | Regional Vice President, Customer Care, Comcast Cable | November 2002 to January 2012 |
| Edward D. Halpin | 54 | Senior Vice President, Power Generation and Chief Nuclear Officer | September 8, 2015 to present |
| | | Senior Vice President and Chief Nuclear Officer | April 2, 2012 to September 8, 2015 |
| | | President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company | December 2009 to March 2012 |
| Kent M. Harvey | 57 | Senior Vice President, Finance, PG&E Corporation | January 1, 2016 to present |
| | | Senior Vice President and Chief Financial Officer, PG&E Corporation | August 1, 2009 to December 31, 2015 |
| | | Senior Vice President, Financial Services | August 1, 2009 to August 17, 2015 |
| Julie M. Kane | 57 | Senior Vice President and Chief Ethics and Compliance Officer | May 18, 2015 to present |
| | | Vice President, General Counsel and Compliance Officer, North America and Corporate Functions, and Compliance Officer, North America, Avon Products, Inc. | September 30, 2013 to March 31, 2015 |
| | | Vice President, Ethics and Compliance, Novartis Corporation | January 1, 2010 to August 31, 2013 |
| Gregory K. Kiraly | 51 | Senior Vice President, Electric Transmission and Distribution | September 8, 2015 to present |
| | | Senior Vice President, Electric Distribution Operations | September 18, 2012 to September 8, 2015 |
| | | Vice President, Electric Distribution Operations | October 1, 2011 to September 17, 2012 |
| | | Vice President, SmartMeter Operations | August 23, 2010 to September 30, 2011 |
| Steven E. Malnight | 43 | Senior Vice President, Regulatory Affairs | September 18, 2014 to present |
| | | Vice President, Customer Energy Solutions | May 15, 2011 to September 17, 2014 |
| | | Vice President, Integrated Demand Side Management | July 1, 2010 to May 14, 2011 |

| | | | |
|---|---|---|---|
| Hyun Park | 54 | Senior Vice President and General Counsel, PG&E Corporation | November 13, 2006 to present |
| Jesus Soto, Jr. | 48 | Senior Vice President, Gas Operations | September 8, 2015 to present |
| | | Senior Vice President, Engineering, Construction and Operations | September 16, 2013 to September 8, 2015 |
| | | Senior Vice President, Gas Transmission Operations | May 29, 2012 to September 15, 2013 |
| | | Vice President, Operations Services, El Paso Pipeline Group | May 2007 to May 2012 |
| Fong Wan | 54 | Senior Vice President, Energy Policy and Procurement | September 8, 2015 to present |
| | | Senior Vice President, Energy Procurement | October 1, 2008 to September 8, 2015 |

(1) Mr. Earley, Mr. Stavropoulos, Ms. Williams, Mr. Simon, Ms. Burt, Ms. Kane, Mr. Park, and Mr. Wells are executive officers of both PG&E Corporation and the Utility. Mr. Harvey is an executive officer of PG&E Corporation only. All other listed officers are executive officers of the Utility only.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 12 , 201 6 , there were 59,317 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal y ears are set forth in the table entitled "Quarterly Consolidated Financial Data (Unaudited)" which appears after the Notes to the Consolidated Financial Statements in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock Utility appears in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of S hareholders' Equity, and Note 5 of the Notes to the Consolidated Financial Statements in Item 8 and in "Li quidity and Financial Resources – Dividends" in Item 7 below.

***Sales of Unregistered Equity Securities***

PG&E Corporation made equity contributions to the Utility totaling $100 million during the quarter ended December 31, 2015. PG&E Corporation did not make any sales of unregistered equity securities during 2015 in reliance on an exemption from registration under the Securities Act of 1933, as amended. However, PG&E Corporation recently discovered, based on a review of new accounts opened under its Dividend Reinvestment and Stock Purchase Plan ("DRSPP") since 2013, that it issued and sold shares of common stock under the optional cash purchase feature of its DRSPP more than three years after the related registration statement for the DRSPP became effective, including approximately 19,550 shares for estimated aggregate sales proceeds of $1 million during the year ended December 31, 2015. As a result, participants who purchased these shares may have a rescission right that would allow them to return the shares to PG&E Corporation in exchange for the purchase price paid by such participants, plus interest, less the value of dividends received.

***Issuer Purchases of Equity Securities***

During the quarter ended December 31, 2015 , PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2015 , the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

**ITEM 6. SELECTED FINANCIAL DATA**

| (in millions, except per share amounts) | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 16,833 | $ 17,090 | $ 15,598 | $ 15,040 | $ 14,956 |
| Operating income | 1,508 | 2,450 | 1,762 | 1,693 | 1,942 |
| Net income | 888 | 1,450 | 828 | 830 | 858 |
| Net earnings per common share, basic (1) | 1.81 | 3.07 | 1.83 | 1.92 | 2.10 |
| Net earnings per common share, diluted | 1.79 | 3.06 | 1.83 | 1.92 | 2.10 |
| Dividends declared per common share (2) | 1.82 | 1.82 | 1.82 | 1.82 | 1.82 |
| **At Year-End** | | | | | |
| Common stock price per share | $ 53.19 | $ 53.24 | $ 40.28 | $ 40.18 | $ 41.22 |
| Total assets | 63,339 | 60,127 | 55,605 | 52,449 | 49,750 |
| Long-term debt (excluding current portion) | 16,030 | 15,050 | 12,717 | 12,517 | 11,766 |
| Capital lease obligations (excluding current portion) (3) | 49 | 69 | 90 | 113 | 212 |
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 16,833 | $ 17,088 | $ 15,593 | $ 15,035 | $ 14,951 |
| Operating income | 1,511 | 2,452 | 1,790 | 1,695 | 1,944 |
| Income available for common stock | 848 | 1,419 | 852 | 797 | 831 |
| **At Year-End** | | | | | |
| Total assets | 63,140 | 59,865 | 55,049 | 51,923 | 49,242 |
| Long-term debt (excluding current portion) | 15,680 | 14,700 | 12,717 | 12,167 | 11,417 |
| Capital lease obligations (excluding current portion) (3) | 49 | 69 | 90 | 113 | 212 |

(1) See "Summary of Changes in Net Income and Earnings per Share " in Item 7. MD&A.

(2) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources – Dividends" in MD&A in Item 7 and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 in Item 8.

(3) The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

**ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

**OVERVIEW**

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility's base revenue requirements are set by the CPUC in its GRC and GT&S rate case and by the FERC in its TO rate cases based on forecast costs. Differences between forecast costs and actual costs can occur for numerous reasons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. Generally, differences between actual costs and forecast costs could affect the Utility's ability to earn its authorized return (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations below). However, for certain operating costs, such as costs associated with pension and other employee benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). The Utility also collects revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers , such as the costs to procure electricity or natural gas for its customers . Therefore, although these costs can fluctuate, they generally do not impact net income (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). See "Ratemaking Mechanisms" in Item 1 for further discussion.

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

**Summary of Changes in Net Income and Earnings per Share**

T he following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS based on earnings from operations) for the year ended December 31, 2015 compared to the year ended December 31, 2014 (see "Results of Operations" below). " Earnings from operations " is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. " Items impacting comparability " represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating plans, and employee incentive compensation . PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance . E arnings from operations are not a substitute or alternative for GAAP measures such as income av ailable for common shareholders and may not be comparable to similarly titled measures used by other companies.

| (in millions, except per share amounts) | | Earnings | | EPS (diluted) |
|---|---|---|---|---|
| **Income Available for Common Shareholders - 2014** | **$** | **1,436** | **$** | **3.06** |
| Natural gas matters [(1)] | | 216 | | 0.45 |
| Environmental-related costs [(2)] | | (4) | | (0.01) |
| **Earnings from Operations - 2014 [(3)]** | $ | **1,648** | **$** | **3.50** |
| Growth in rate base earnings | | 105 | | 0.22 |
| Timing of 2015 GT&S cost recovery [(4)] | | (208) | | (0.43) |
| Regulatory and legal matters [(5)] | | (16) | | (0.04) |
| Gain on disposition of SolarCity stock [(6)] | | (13) | | (0.03) |
| Increase in shares outstanding | | - | | (0.12) |
| Miscellaneous | | 3 | | 0.02 |
| **Earnings from Operations - 2015 [(3)]** | **$** | **1,519** | **$** | **3.12** |
| Insurance recoveries [(7)] | | 29 | | 0.06 |
| Fines and penalties [(8)] | | (578) | | (1.19) |
| Pipeline-related expenses [(9)] | | (61) | | (0.13) |
| Legal and regulatory related expenses [(9)] | | (35) | | (0.07) |
| **Income Available for Common Shareholders - 2015** | **$** | **874** | **$** | **1.79** |

(1) In 2014, natural gas matters included pipeline-related costs to perform work under the PSEP and other activities associated with safety improvements to the Utility's natural gas system, as well as legal and other costs related to natural gas matters. Natural gas matter s also included charges related to fines, third party liability claims, and insurance recoveries in 2014.
(2) In 2014, the Utility reduced its accrual related to the Hinkley whole house water replacement program.
(3) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in n otes (1) and (2) above and Notes ( 7 ), ( 8 ), and ( 9 ) below.
(4) Represents expenses during the year ended December 31, 2015 as compared to 2014, with no corresponding increase in revenue. The Utility has requested that the CPUC authorize an increase to the Utility's revenue requirements for 2015, 2016, and 2017 in its 2015 GT&S rate case , and exp ects a final decision in 2016 . A ny revenue requirement increase that the CPUC may authorize would be retroactive to January 1, 2015 but would be recorded in the period a final decision is issued .
(5) Includes legal and other regulatory related costs that were partially offset by incentive revenues .
(6) Represents the larger gain recognized during the year ended December 31, 2014 as compared to 2015.
(7) Represents insurance recoveries of $49 million, pre-tax, for third party claims and associated legal costs related to the San Bruno accident the Utility received during the year ended December 31, 2015. The Utility has received a cumulative total of $515 million through insurance related to $558 million of third-party claims and $92 million of legal costs incurred. No further insurance recoveries related to thes e claims and costs are expected .
(8) Represents the impact of the Penalty Decision (see Note 13 of the Notes to the Consolidated Financial Statements in Item 8. for before-tax amounts) .
(9) In 2015, pipeline-related expenses include costs incurred to identify and remove encroachments from transmission pipeline rights of way and to performremaining work under the Utility's PSEP. Legal and regulatory related expenses include costs incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

**Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows**

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materiall y affected by the following factors:

- *The Outcome of Enforcement and Litigation Matters.* Future financial results will be impacted by the unrecoverable pipeline safety-related and remedies costs required by the Penalty Decision. The Utility's future results may also be impacted by various other pending enforcement and regulatory actions, including the federal criminal charg es and CPUC investigations of the Utility's compliance with natural gas distribution record-keeping practices and potential violations of the CPUC's ex parte communication rules. (See "Enforcement and Litigation Matters" in Note 13 of the N otes to the Consolidated Financial Statements in Item 8 .)

- *T he Timing and Outcome of Regulatory Matters* . The 2015 GT&S rate case remains pending. T he Utility requested that the CPUC authorize a $532 million increase in annual revenue requirements for gas transmission and storage operations beginning on January 1, 2015 with attrition increases in 2016 and 2017. Any revenue requirement increase that the CPUC may authorize would be retroactive to January 1, 2015 but would be recorded in the period a final decision is reached . (See " Regulatory Matters − 2015 Gas Transmission and Storage Rate Case" below for more information.) In September 2015, the Utility filed its 2017 GRC application to request that the CPUC authorize revenue requirements for the Utility's electric generation business and its electric and natural gas distribution business for 2017 through 2019. (See " Regulatory Matters − 2017 General Rate Case" below for more information.) In addition, the Utility has one transmission owner rate case pending at the FERC (See " Regulatory Matters – FERC TO Rate Cases" below . ) The outcome of regulatory proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other facto rs .

- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* Whether the Utility is able to earn its authorized rate of return could be materially affected if the Utility's actual costs differ from the amounts authorized in the rate case decisions. In addition to incurring shareholder-funded costs and costs associated with remedial measures required by the Penalty Decision, t he Utility also forecasts that in 201 6 it will incur unrecovered pipeline-related expenses ranging from $ 100 million to $150 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way . The ultimate amount of unrecovered costs also could be affected by how the CPUC determines which costs are included in determining whether the $850 million shareholder-funded obligation under the Penalty Decision has been met, and the outcome of pending and future investigations and enforcement matters. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 .) The Utility's ability to recover costs in the future also could be affected by decreases in customer demand driven by legislative and regulatory initiatives relating to distributed generation resources, renewable energy requirements, and changes in the electric rate structure.

- *The Amount and Timing of the Utility's Financing Needs.* PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-au thorized capital structure. In 201 5 , PG&E Corporation issued $ 801 million of common stock with cash proceeds and made equity contributions to the Utility of $ 705 million. PG&E Corporation forecasts that it will issu e a material amount of equity in 2016 and future years to support the Utility's capital expenditures . PG&E Corporation will issue additional equity to fund charges incurred by the Utility to comply with the Penalty Decision, to fund unrecoverable pipeline-related expenses, and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances would have a material dilutive impact on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 , Financial Statements and Supplementary Data , changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors . In addition, this 201 5 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Cautionary Language Regarding Forward - Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2015 , 2014 , and 2013 . See " Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows " above for further discussion about factors that could affect future results of operations.

### PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders :

| (in millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Consolidated Total | $ 874 | $ 1,436 | $ 814 |
| PG&E Corporation | 26 | 17 | (38) |
| Utility | $ 848 | $ 1,419 | $ 852 |

PG&E Corporation's net income or loss consists primarily of interest expense on long-term debt, other income or loss from investments, and income taxes. Results include approximately $30 million and $45 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in 2015 and 2014, respectively. PG&E Corporation's operating results i n 2013 reflected an impairment loss of $29 million related to tax equity fund investments .

### Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2015 , 2014 , and 2013 . The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

The Utility's operating results for 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

| | 2015 | | | 2014 | | | 2013 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Revenues and Costs: | | | Revenues and Costs: | | | Revenues and Costs: | | |
| **(in millions)** | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
| Electric operating revenues | $ 7,442 | $ 6,215 | $ 13,657 | $ 7,059 | $ 6,597 | $ 13,656 | $ 6,465 | $ 6,024 | $ 12,489 |
| Natural gas operating revenues | 2,082 | 1,094 | 3,176 | 2,072 | 1,360 | 3,432 | 1,776 | 1,328 | 3,104 |
| **Total operating revenues** | **9,524** | **7,309** | **16,833** | **9,131** | **7,957** | **17,088** | **8,241** | **7,352** | **15,593** |
| Cost of electricity | - | 5,099 | 5,099 | - | 5,615 | 5,615 | - | 5,016 | 5,016 |
| Cost of natural gas | - | 663 | 663 | - | 954 | 954 | - | 968 | 968 |
| Operating and maintenance | 5,402 | 1,547 | 6,949 | 4,247 | 1,388 | 5,635 | 4,374 | 1,368 | 5,742 |
| Depreciation, amortization, and decommissioning | 2,611 | - | 2,611 | 2,432 | - | 2,432 | 2,077 | - | 2,077 |
| **Total operating expenses** | **8,013** | **7,309** | **15,322** | **6,679** | **7,957** | **14,636** | **6,451** | **7,352** | **13,803** |
| **Operating income** | **1,511** | **-** | **1,511** | **2,452** | **-** | **2,452** | **1,790** | **-** | **1,790** |
| Interest income [(1)] | | | 8 | | | 8 | | | 8 |
| Interest expense [(1)] | | | (763) | | | (720) | | | (690) |
| Other income, net [(1)] | | | 87 | | | 77 | | | 84 |
| **Income before income taxes** | | | 843 | | | 1,817 | | | 1,192 |
| Income tax (benefit) provision [(1)] | | | (19) | | | 384 | | | 326 |
| **Net income** | | | 862 | | | 1,433 | | | 866 |
| Preferred stock dividend requirement [(1)] | | | 14 | | | 14 | | | 14 |
| **Income Available for Common Stock** | | | **$ 848** | | | **$ 1,419** | | | **$ 852** |

[(1)] These items impacted earnings.

**Utility Revenues and Costs that Impacted Earnings**

The following discussion presents the Utility's operating results for 2015 , 2014 , and 2013 , focusing on revenues and expenses that impacted earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues increased $ 393 million or 4% in 2015 compared to 2014 , primarily a result of approximately $490 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case. This increase was partially offset by the absence of approximately $110 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the same period in 2014.

The Utility's electric and natural gas operating revenues that impacted earnings increased $ 890 million or 11% in 2014 compared to 2013 . This amount include d an increase to base revenues of $460 million as authorized by the CPUC in the 2014 GRC decision. T he GRC decision also resulted in higher base revenues of $150 million in 2014 related primarily to the DOE settlement for sp ent nuclear fuel storage costs. The total incr ease in operating revenues include d approximately $150 millio n of PSEP-related revenues, and revenues authorized by the FERC in the TO rate case , as well as revenues authorized by the CPUC for recovery of nuclear decommissioning costs. The Utility also collected higher gas transmission revenues driven by increased demand for gas-fired generation.

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings in creased $ 1.2 b illion or 27% in 2015 compared to 2014 , primarily due to $ 907 million in charges associated with the Penalty Decision , consisting of $400 million for the customer bill credit, an additional $100 million charge for the f ine payable to the state , and $407 million of disallowed capital charges. ( See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 . ) The increase is also due to higher labor and ben efit-related expenses of approximately $100 million and fewer insurance recoveries for third-party claims and associated legal costs of $63 million related to the San Bruno accident . No further insurance recoveries related to these claims are expected. These increases were offset by $116 million in disallowed capital recorded in 2014 related to the PSEP.

The Utility's operating and maintenance expenses that impacted earnings decreased $127 millio n or 3% in 2014 compared to 2013 , primarily due to lower third-party claims and associated legal costs of $117 million resulting from the settlement of all outstanding third-party claims, lower disallowed capital expenditures of $80 million and lower insurance recoveries for third-party claims and associated legal costs of $42 million related to the San Bruno accident . These decreases were offset by higher benefit-related expenses and other operating expenses of $120 million in 2014 as compared to 2013 .

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased $ 179 million or 7% in 2015 compared to 2014 and $ 355 million or 17% in 2014 compared to 2013 . In 2015, the increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by the FERC in the TO rate case . In 2014, the increase was primarily due to higher depreciation rates as authorized by the CPUC in the 2014 GRC decision and higher nuclear decommissioning expense reflecting the year-to-date increase as authorized by the CPUC in the nuclear decommissioning triennial proceeding. Additionally, depreciation, amortization, and decommissioning expenses were impacted by an increase in capital additions during 2014 as compared to 2013 .

*Interest Expense*

The Utility's interest expenses increased by $ 43 million in the year ended December 31, 2015 compared to the same period in 2014, primarily due to the issuance of additional long-term debt. There were no material changes to interest expense in the year ended December 31, 2014 compared to the same period in 2013.

*Interest Income and Other Income, Net*

There were no material changes to interest income and other income, net for the periods presented.

*Income Tax Provision*

The Utility's revenue requirements for the 2014 GRC decision period reflects flow-through ratemaking for income tax expense benefits attributable to the accelerated recognition of repair costs and certain other property-related costs for federal tax purposes. PG&E Corporation and the Utility's effective tax rates for 2015 are lower as compared to 2014 and for 2014 as compared to 2013 and are expected to remain lower than the statutory rate in 2016 due to these temporary differences.

The Utility's income tax provision dec reased $ 403 million or 105% in 2015 as compared to 2014 . This is primarily the result of the statutory tax effect, $397 million, of the lower i ncome b efore i ncome t axes in 2015 as compared to 2014 . T he lower effective tax rate is the result of the tax benefits from property-related timing differences applied to this lower income before income taxes.

T he Utility's income tax provision inc reased $ 58 million or 18% in 2014 as compared to 2013 primarily due to higher i ncome b efore i ncome t axes , partially offset by certain reductions in tax expense for flow-through treatment as discussed above.

The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) [(1)] | (4.8) | 1.6 | (2.2) |
| Effect of regulatory treatment of fixed asset differences [(2)] | (33.7) | (14.7) | (3.8) |
| Tax credits | (1.3) | (0.7) | (0.4) |
| Benefit of loss carryback | (1.5) | (0.8) | (1.0) |
| Non-deductible penalties [(3)] | 4.3 | 0.3 | 0.7 |
| Other, net | (0.2) | 0.4 | (0.9) |
| **Effective tax rate** | **(2.2) %** | **21.1 %** | **27.4 %** |

[(1)] Includes the effect of state flow-through ratemaking treatment. In 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.
[(2)] I nclude s the effect of federal flow-through ratemaking treatment for certain property-related costs in 2015 and 2014 as authorized by the 2014 GRC decision. Amounts are impacted by the level of income before income taxes.
[(3)] Represen ts the effect s of non-tax deductible fines and penalties associated with the Penalty Decision . For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 .

**Utility Revenues and Costs that did not Impact Earnings**

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs, see below for more detail.

*Cost of Electricity*

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

| **(in millions)** | 2015 | 2014 | 2013 |
|---|---|---|---|
| Cost of purchased power [(1)] | $ 4,805 | $ 5,266 | $ 4,696 |
| Fuel used in own generation facilities | 294 | 349 | 320 |
| **Total cost of electricity** | **$ 5,099** | **$ 5,615** | **$ 5,016** |
| Average cost of purchased power per kWh | $ 0.100 | $ 0.101 | $ 0.094 |
| **Total purchased power (in millions of kWh) [(2)]** | **48,175** | **52,008** | **49,941** |

[(1)] C ost of purchased power was impacted primarily by a decline in the market price of natural gas in 2015 compared to 2014.
[(2)] T he decrease in purchased power resulted from an increase in generation from the Utility's own generation facilities. Gas-fired and nuclear generation increased during the year ended December 31, 2015 as compared to the same periods in 2014.

The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including the Diablo Canyon nuclear generation power plant and hydroelectric plants), and the cost-effectiveness of each source of electricity .

*Cost of Natural Gas*

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

| **(in millions)** | | **2015** | | **2014** | | **2013** |
|---|---|---|---|---|---|---|
| Cost of natural gas sold | $ | 518 | $ | 813 | $ | 807 |
| Transportation cost of natural gas sold | | 145 | | 141 | | 161 |
| **Total cost of natural gas** | **$** | **663** | **$** | **954** | **$** | **968** |
| Average cost per Mcf [(1)] of natural gas sold [(2)] | $ | 2.74 | $ | 4.37 | $ | 3.54 |
| **Total natural gas sold (in millions of Mcf)** | | **189** | | **186** | | **228** |

[(1)] One thousand cubic feet
[(2)] Average cost of natural gas sold impacted primarily by a decline in the market price of natural gas in 2015 compared to 2014.

*Operating and Maintenance Expenses*

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2015, 2014 , and 2013, no material amounts were incurred above authorized amounts.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect related to its financing costs. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock. (See "Ratemaking Mechanisms" in Item 1) . The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility , and pay dividends , primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and borrowings and repayments under its revolving credit facility. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of the pending enforcement and litigation matters. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper , the costs associated with credit facilities, and l ong-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability positions . (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporatio n forecasts that it will issue between $6 00 million and $800 million in common stock during 2016 , primarily to fund equity contributions to the Utility. T he Utility's future equity needs will continue to be affected by charges incurred to comply with the Penalty Decision, by unrecoverable pipeline-related expenses, and by fines and penalties that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below . Common stock issuances by PG&E Corporation to fund these needs would have a material dilutive impact on PG&E Corporation's EPS .

**Cash and Cash Equivalents**

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility is uncertain when and how the remaining disputed claims will be resolved.

**Financial Resources**

***Debt and Equity Financings***

The Utility issued $1.15 billion in long-term debt during the year ended December 31, 2015. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

In February 2015, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $500 million. During 2015, PG&E Corporation sold 1.4 million shares of common stock under this agreement for cash proceeds of $ 74 million, net of commissions paid of $1 million.

In August 2015, PG&E Corporation sold 6.8 million shares of its common stock in an underwritten public offering for cash proceeds of $352 million, net of fees.

In addition, d uring 2015, PG&E Corporation sold 7.9 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $ 354 million .

The proceeds from equity issuances were used for general corporate purposes, including the contribution of equity into the Utility . For the year ended December 31, 2015 , PG&E Corporation made equity contributions to the Utility of $ 705 million, of which $300 million was used to pay a fine to the State General Fund as required by the Penalty Decision. Additionally, PG&E Corporation and the Utility expect to continue to issue long-term and short-term debt for general corporate purposes and to maintain the CPUC-authorized capital structure during 2016.

***Revolving Credit Facilities and Commercial Paper Programs***

At December 31, 2015, PG&E Corporation and the Utility had $ 300 million and $ 1.9 billion available under their respective $ 300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

T he revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At December 31, 2015, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51% and 50 % , respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At December 31, 2015 , PG&E Corporation and the Utility were in compl iance with all covenants under their respective revolving credit facilities.

**Dividends**

***PG&E Corporation***

For each of the quarters in 2015 , 2014 , and 2013 , t he Board of Directors of PG&E Corporation declared common stock dividends o f $ 0.455 p er share, for annual dividends of $ 1.82 per share. Dividends paid to common stockholders by PG&E Corporation were $ 856 million in 2015 , $ 828 million in 2014 , and $ 782 million in 2013 . In December 2015, the Board of Directors of PG&E Corporation declared quarterly dividends of $ 0.455 per share, totali ng $ 224 milli on, of which approximately $ 219 mil lion was paid on January 15, 2016 to shareholders of record on December 31, 2015.

***Utility***

For each of the quarters in 2015 , 2014 , and 2013 , the Utility's Board of Directors declared common stock dividends in the aggregate amount of $ 179 million to PG&E Corporation for annual dividends paid of $ 716 million in each of 2015 , 2014 , and 2013 . In addition, the Utility paid $ 14 million of dividends on preferred stock in each of 2015 , 2014 , and 2013 . The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends. In December 2015, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable o n February 15, 2016, to shar eholders of record on January 29 , 2016.

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2015** | **2014** | **2013** |
| Net cash provided by operating activities | $ 3,720 | $ 3,619 | $ 3,416 |
| Net cash used in investing activities | (5,211) | (4,799) | (5,142) |
| Net cash provided by financing activities | 1,495 | 1,170 | 1,597 |
| **Net change in cash and cash equivalents** | **$ 4** | **$ (10)** | **$ (129)** |

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During 2015 , net cash provided by operating activities increased by $ 101 million compared to 2014 . This increase was primarily due to higher base revenue collections authorized in the 2014 GRC and lower purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above), offset by the payment of a $300 million fine to the State General Fund as required by the Penalty Decision. During 2014 , net cash provided by operating activities increased by $203 million compared to 2013 . This increase was primarily due to tax refunds received during 2014 compared to tax payments made during 2013 and additional collateral returned to the Utility in 2014 as compared to 2013, offset by higher purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above) .

Future cash flow from operating activities will be affected by various factors, including:

- the shareholder-funded bill credit of $400 million to natural gas customers in 2016, as required by the Penalty Decision (see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements);
- the timing and amounts of other fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement matters (see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below);
- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system (including costs to implement remedial measures and $850 million to pay for designated pipeline safety projects and programs, as required by the Penalty Decision);
- the timing and amount of tax payments (including the bonus depreciation extension) , tax refunds, net collateral paym ents, and interest payments;
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

***Investing Activities***

Net cash used in investing activities increased by $ 412 million during 2015 as compared to 2014 primarily due to an increase of $340 million in capital expenditures and an increase in net purchases of nuclear decommissioning trust investments in 2015 as compared to net proceeds associated with sales of nuclear decommissioning trust investments in 2014 .  Net cash used in investing activities decreased by $343 million during 2014 as compared to 2013 primarily due a decrease of $374 million in capital expenditures. This decrease was primarily due to lower PSEP-related capital expenditures and the absence of additional investment in the Utility's photovoltaic program.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur between $5. 4 billion and $5. 6 billion i n 2016 .

***Financing Activities***

During 2015 , net cash provided by financing activities increased by $ 325 million as compared to 2014 . During 2014 , net cash provided by financing activities decreased by $427 million as compared to 2013 . Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

**CONTRACTUAL COMMITMENTS**

The following table provides information about PG&E Corporation 's and the Utility's contractual commitments at December 31, 2015 :

| | Payment due by period | | | | |
|---|---|---|---|---|---|
| (in millions) | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years | Total |
| **Utility** | | | | | |
| Long-term debt [1] : | $ 917 | $ 2,991 | $ 2,888 | $ 22,150 | $ 28,946 |
| Purchase obligations [2] : | | | | | |
| Power purchase agreements: | 3,453 | 6,508 | 6,035 | 31,824 | 47,820 |
| Natural gas supply, transportation, and storage | 421 | 255 | 208 | 543 | 1,427 |
| Nuclear fuel agreements | 113 | 196 | 231 | 185 | 725 |
| Pension and other benefits [3] | 388 | 776 | 776 | 388 | 2,328 |
| Operating leases [2] | 40 | 81 | 76 | 195 | 392 |
| Preferred dividends [4] | 14 | 28 | 28 | - | 70 |
| **PG&E Corporation** | | | | | |
| Long-term debt [1] : | 8 | 16 | 351 | - | 375 |
| **Total Contractual Commitments** | **$ 5,354** | **$ 10,851** | **$ 10,593** | **$ 55,285** | **$ 82,083** |

[1] Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2015 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)
[2] See "Purchase Commitments" and "Other Commitments" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.
[3] See Note 11 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.
[4] Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

The contractual commitments table above excludes potential payments associated with unrecognized tax positions . Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amount s and period s of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 8 of the Notes to the Consolidated Financial Statements in Item 8 .

**O ff-Balance Sheet Arrangements**

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources , other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) in Item 8 .

**ENFORCEMENT AND LITIGATION MATTERS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 . The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results.

*Department of Interior Inquiry*

In September 2015, the Utility was notified that the U.S. Department of Interior ("DOI") had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the allegations contained in the superseding criminal indictment (See Note 13 in the Consolidated Financial Statements in Item 8) . The Utility filed its initial response on November 2, 2015 , to demonstrate that it is a presently responsible contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate. It is uncertain when or if further action will be taken.

**Pending Lawsuits and Claims**

As of December 31, 2015, there were six purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the *San Bruno Fire Derivative Cases* and are pending in the Superior Court of California, County of San Mateo. On August 28, 2015, the Superior Court overruled the demurrers filed by PG&E Corporation, the Utility and the individual director and officer defendants seeking to dismiss the *San Bruno Fire Derivative Cases* , based upon the plaintiffs' failure to demand action by the Boards of PG&E Corporation and the Utility prior to filing the complaint. After the ruling, and pursuant to co-petitions for writ of mandate previously filed by PG&E Corporation, the Utility, and the individual defendants, on September 3, 2015 the California Court of Appeal issued an order staying the *San Bruno Fire Derivative Cases* pending the court's final determination whether to stay the matter altogether until the resolution of federal criminal proceedings against the Utility. On September 30, 2015, PG&E Corporation, the Utility, and the individual defendants filed an additional petition for writ of mandate asking the Court of Appeal to review the lower court's August 28 decision overruling their demurrers. On October 22, 2015, the Court of Appeal issued a ruling declining to review the August 28 decision. On December 8, 2015, the Court of Appeal issued a writ of mandate to the Superior Court, ordering the Superior Court to stay all proceedings in the *San Bruno Fire Derivative Cases* "pending conclusion of the federal criminal proceedings" against the Utility. The other two derivative actions are entitled *Tellardin v. PG&E Corp. et. al.* , pending in the Superior Court of California, San Mateo County, and *Iron Workers Mid-South Pension Fund v. Johns, et. al* ., pending in the United States District Court for the Northern District of California. PG&E Corporation, and the other defendants have not answered or otherwise responded to the complaints in these actions . In the *Tellardin* action, the defendants must answer or respond to the complaint 30 days after the stay in the *San Bruno Fire Derivative Cases* is lifted. In the *Iron Workers* action, the court has not established a deadline by which the defendants must an swer or respond. Case management conferences have been scheduled in both actions (March 21, 2016 in the *Tellardin* action and June 3, 2016 in the *Iron Workers* action), after which PG&E Corporation will have more information about any further proceedings in these actions.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

**R EGULATORY MATTERS**

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

**2017 General Rate Case**

On September 1, 2015, the Utility filed its 2017 GRC application with the CPUC. In the 2017 GRC, the Utility has requested that the CPUC determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. (The Utility's revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings ove rseen by the CPUC or the FERC.) In its application, the Utility requested a revenue requirement increase of $457 million, as compared to authorized base revenues for 2016, as shown in the following tables:

| **Line of Business:**<br>(in millions) | **Amounts Requested In the GRC Application** | **Amounts Currently Authorized For 2016** | **Increase Compared to Currently Authorized Amounts** |
|---|---|---|---|
| Electric distribution | $ 4,376 | $ 4,212 | $ 164 |
| Gas distribution | 1,827 | 1,742 | 85 |
| Electric generation | 2,170 | 1,962 | 208 |
| **Total revenue requirements** | **$ 8,373** | **$ 7,916** | **$ 457** |
| | | | |
| **Cost Category:** | | | |
| (in millions) | | | |
| Operations and maintenance | $ 1,833 | $ 1,664 | $ 169 |
| Customer services | 367 | 319 | 48 |
| Administrative and general | 978 | 1,011 | (33) |
| Less: Revenue credits | (140) | (131) | (9) |
| Franchise fees, taxes other than income, and other adjustments | 185 | 37 | 148 |
| Depreciation (including costs of asset removal), return, and income taxes | 5,150 | 5,016 | 134 |
| **Total revenue requirements** | **$ 8,373** | **$ 7,916** | **$ 457** |

In its application, the Utility stated that over the 2017-2019 GRC period the Utility plans to make average annual capital investments of approximately $4 billion in electric distribution, natural gas distribution and electric generation infrastructure, and to improve safety, reliability, and customer service. (These annual investments would be incremental to the Utility's capital expenditures for electric and natural gas transmission infrastructure.) The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized revenues in 2018 and 2019, primarily to reflect increases in rate base due to capital investments in infrastructure and, to a lesser extent, anticipated increases in wages and other expenses. The Utility estimates that this mechanism would result in increases in revenue of $489 million in 2018 and an additional $390 million in 2019.

In October 2015, the Utility filed supplemental testimony to reduce its original revenue requirement request by approximately $17 million per year based on its forecast that it will incur approximately $61 million for unrecoverable costs to implement the remedies ordered in the Penalty Decision.

On February 22, 2016 the Utility will file an update of its forecasted increase, primarily to reflect the impact of the recent five-year extension of the federal tax code provisions regarding bonus depreciation.

According to the CPUC's current procedural schedule, testimony from the ORA and other parties is due in April 2016, evidentiary hearings are to be held this summer, followed by a proposed decision to be released in November 2016 and a final CPUC decision to be issued in December 2016. The Utility has requested that the CPUC issue an order directing that the authorized revenue requirement changes be effective January 1, 2017, even if the final decision is issued after that date.

**2015 Gas Transmission and Storage Rate Case**

In the 2015 GT&S rate case, the Utility requested that the CPUC authorize a 2015 revenue requirement of $1.263 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $532 million over currently authorized amounts. The Utility also requested attrition increases of $83 million in 2016 and $142 million in 2017. The Utility requested that the CPUC authorize the Utility's forecast of its 2015 weighted average rate base for its gas transmission and storage business of $3.44 billion, which includes capital spending above authorized levels for the prior rate case period.

The ORA has recommended a 2015 revenue requirement of $1.044 billion, an increase of $329 million over authorized amounts. TURN recommended that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service after January 1, 1956, as well as certain other work that TURN considers to be remedial. TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of capital expenditures during this period be subject to a reasonableness review and an independent audit. TURN states that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit. On December 18, 2015, the ORA filed a motion in the 2015 GT&S rate case for an Order to Show Cause why the Utility should not be sanctioned $163 million for intentional misrepresentations regarding its compliance with gas safety regulations regarding maximum allowable operating pressure f or its gas transmission lines. On December 30 , 2015, the Utility filed a response to this motion stating that it does not believe there is merit to the allegations. ORA filed a reply on January 11, 2016, reiterating its allegations.

The Utility also has proposed changes to the revenue sharing mechanism authorized in the last GT&S rate case (covering 2011-2014) that subjected a portion of the Utility's transportation and storage revenue requirement to market risk. The Utility proposed full balancing account treatment that allows for recovery of the Utility's authorized transportation and storage revenue requirements (except for the revenue requirement associated with the Utility's 25% interest in the Gill Ranch storage field).

Based on the scoping ruling and procedural schedule that was issued on June 11, 2015, the CPUC plans to issue an initial decision to authorize revenue requirements followed by a second decision to reduce the authorized revenue requirements by the costs of designated safety-related projects and programs up to the $850 million maximum cost disallowance imposed by the Penalty Decision. (See Note 13 in the Consolidated Financial Statements in Item 8 for more information about the CPUC's Penalty Decision.) In accordance with an earlier CPUC decision regarding the Utility's violation of the CPUC's ex parte communication rules made in the GT&S rate case, the first decision could disallow the Utility from recovering up to a five-month portion of the revenue increase that may otherwise have been authorized. It is uncertain how much of the Utility's costs to perform the safety-related projects and programs the CPUC will identify as count ing toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. Additionally, the Utility may record additional charges if the CPUC does not authorize capital spending from the prior rate case period. The authorized revenue requirements in the GT&S rate case would be retroactive to January 1, 2015. The ruling states that the case would be completed within 18 months of the date of the ru ling, or by December 2016.

**FERC TO Rate Cases**

On September 30, 2015, the FERC approved a settlement that sets the Utility's 2015 retail electric transmission revenue requirement at $1.201 billion, a $161 million increase over the currently authorized revenue requirement of $1.040 billion.

On July 29, 2015, the Utility requested that the FERC approve a 2016 retail electric transmission revenue requirement of $1.515 billion. The proposed amount reflects a $314 million increase over the settled revenue requirement of $1.201 billion. The Utility forecasts that it will make investments of $1.246 billion in 2016 in various capital projects. The Utility's forecasted rate base for 2016 is $5.85 billion, compared to forecasted rate base of $5.12 billion in 2015. The Utility has requested that the FERC approve a 10.96% return on equity. On September 30, 2015, the FERC accepted the proposed revenue requirement, subject to hearing and refund, and established March 1, 2016 as the effective date for rate changes. Hearings are being held in abeyance pending settlement discussions among the parties.

**CPUC Investigation of the Utility's Safety Culture**

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned Commissioner will determine the scope of and next actions in the proceeding. The timing scope and potential outcome of the investigation are uncertain.

**Diablo Canyon Nuclear Power Plant**

The NRC operating licenses for the two nuclear generation units at Diablo Canyon expire in 2024 and 2025. In November 2009, the Utility filed an application with the NRC to seek the renewal of the operating licenses, a process which can take several years. After the March 2011 earthquake in Japan that damaged nuclear facilities, the NRC granted the Utility's request to delay processing its renewal application until certain advanced seismic studies of the fault zones in the region surrounding Diablo Canyon were completed. The seismic studies have been completed and in September 2014, the Utility submitted a report to the NRC and the CPUC's Independent Peer Review Panel ("IPRP") that confirmed the seismic safety of the plant. The IPRP is providing comments on the report and the Utility expects the IPRP to conclude their review and issue a final report in 2016. In addition, the Utility has requested that the California State Lands Commission extend the leases for the land occupied by Diablo Canyon's water intake and discharge structures from the current expiration dates in 2018 and 2019 to 2024 and 2025 when the NRC operating licenses are currently due to expire. The California State Lands Commission has deferred acting on the application until later in 2016. It is uncertain whether the leases will be extended or whether an environmental review will be required before the commission can issue a decision. Finally, the California Water Board is not expected to issue a final decision before January 1, 2017 to address how the Utility's nuclear operations at Diablo Canyon must comply with the state's policy regarding once-through cooling. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024. Based on these and other factors, the Utility is continuing to assess its strategy for license renewal of Diablo Canyon. (See Item 1A. Risk Factors and "Environmental Regulation" in Item 1. For a discussion of the Utility's nuclear decommissioning obligations, see Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statements in Item 8.)

**LEGISLATIVE AND REGULATORY INITIATIVES**

The California Legislature and the CPUC have adopted requirements and policies to accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles, and promote customer energy efficiency and demand response programs. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. CPUC proceedings related to some of these matters are discussed below.

In addition, prompted by a methane gas leak from a natural gas storage facility located in Southern California, the California Legislature has begun to consider adopting new legislation to address natural gas storage operations in California, including increased oversight of natural gas storage facilities and the adoption of new safety and reliability measures. The California Governor also issued an emergency proclamation that requires various state agencies to take immediate action, as discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

*Natural Gas Storage Facilities*

On January 6, 2016 the California Governor order ed the Division of Oil, Gas and Geothermal Resources ( " DOGGR " ) to issue emergency regulations to require gas storage facility operators throughout California , including the Utility, to comply with new safety and reliability measures, including minimum daily inspection of gas storage well heads (using gas leak detection technology such as infrared imaging), ongoing verification of the mechanical integrity of all gas storage wells, ongoing measurement of annular gas pressure or annular gas flow within wells, regular testing of all safety valves used in wells, establishing minimum and maximum pressure limits for each gas storage facility in the state, and establishing a comprehensive risk management plan that evaluates and prepares for risks at each facility, including corrosion potential of pipes and equipment. The Utility may incur significant costs to comply with the new regulations but anticipates that it would be able to recover such costs through rates.

The DOGGR, the CPUC, the CARB, and the CEC will be required to submit to the California Governor's Office a report that assesses the long-term viability of natural gas storage facilities in California. The report will address operational safety and potential health risks, methane emissions, supply reliability for gas and electricity demand in California, and the role of storage facilities and natural gas infrastructure in the State's long-term GHG emission reduction strategies.

*New Renewable Energy Targets*

In October 2015, the California Governor signed SB 350 which, effective January 1, 2016, increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period and in each compliance period thereafter. SB 350 includes increasing interim renewable energy targets for the periods between 2020 and 2030 and continues to include compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets which the Utility expects will continue to be recoverable from customers as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher targets.

*Electric Distribution Resources Plan*

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of distributed energy resources. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. The Utility's 2017 GRC includes a request to recover some of the investment costs that it forecasts it will incur under its proposed electric distribution resources plan.

*Electric Rate Reform and Net Energy Metering ("NEM")*

On July 3, 2015, the CPUC approved a final decision to authorize the California investor–owned utilities to gradually flatten their tiered residential electric rate structures from four tiers to two tiers by January 1, 2019. The decision approved increased minimum bill charges for residential customers and also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential electric customers based on time-of-use rates unless customers elect otherwise (known as "default time-of-use rates"). The Utility also may propo se to impose a fixed charge on residential electric c ustomers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge in electric rates .

In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates are expected t o become effective for new NEM customers of the Utility later in 2016. New NEM customers will be required to pay an interconnection fee, will go on time of use rates, and will be required to pay non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay.

*Electric Vehicle (EV) Infrastructure Development*

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing an EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain more than 25,000 EV charging stations and the associated infrastructure. The Utility proposed to engage with third party EV equipment and service providers to operate and maintain the charging stations. The Utility requested that the CPUC approve forecasted capital expenditures of $551 million over the 5 year deployment period.

On September 4, 2015, the assigned CPUC Commissioner and the ALJ issued a scoping memo and procedural schedule that required the Utility to supplement its application by submitting a more phased deployment approach that will be considered in a first phase of the proceeding. On October 12, 2015, the Utility submitted supplemental testimony presenting two separate proposals. In its first proposal, the Utility has requested that the CPUC approve approximately $70 million in capital expenditures to deploy and own 2,510 EV charging stations over approximately 2 years. In its second proposal, the Utility has requested that the CPUC approve approximately $187 million in capital expenditures to deploy and own 7,530 EV charging stations over approximately 3 years. Under the CPUC's schedule, a proposed decision for the first phase of the proceeding is expected to be issued by June 2016. Further deployment of EV charging stations would be considered in a second phase of the proceeding depending on the outcome of the first phase.

**ENVIRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of $CO_2$ and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Item 1A. Risk Factors and "Environmental Regulation" in Item 1 .)

**Natural Gas Compressor Station Sites**

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment. At December 31, 2015 , $ 140 million and $ 300 million was accrued in the Consolidated Balances Sheets for estimated undiscounted remediation costs associated with the Hinkley site and the Topock site, respectively. Costs associated with the Hinkley site are not recovered through rates. (See "Environmental Remediation Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 .)

**RISK MANAGEMENT ACTIVITIES**

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non- speculative purposes ( i.e ., risk mitigation). The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

**Commodity Price Risk**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings . Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs through fixed reservation charges and volumetric charges from long-term contracts , resulting in price and volumetric risk. (See " 2015 Gas Transmission and Storage Rate Case" above . )

The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $ 2 million and $1 million at December 31 , 2015 and 2014 , respectively . During 2015 , t he Utility's approximate high, low, and average values-at-risk were $ 2 million, $ 1 million and $ 2 million, respectively. During 2014 , the value-at-risk amounts were $9 million, $1 million and $5 million, respectively . ( See Note 9 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.)

**Interest Rate Risk**

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. A t December 31 , 2015 and 2014 , if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments , th e impact on net income over the next 12 months would be $ 11 million and $9 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. ( See Note 4 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of interest rates .)

**Energy Procurement Credit Risk**

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit c ollateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit c ollateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's energy procurement credit risk exposure to its counterparties :

| (in millions) | Gross Credit Exposure Before Credit Collateral [1] | Credit Collateral | Net Credit Exposure [2] | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| December 31, 2015 | $ 64 | $ (11) | $ 53 | 4 | 39 |
| December 31, 2014 | 88 | $ (18) | $ 70 | 3 | 29 |

[1] Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.
[2] Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

## CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

### Regulatory Accounting

As a regulated entity, t he Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2015 , PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $ 9.3 billion and regulatory liabilities (including current balancing accounts payable) of $ 7.7 billion .

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation , the Utility has determined that the costs are recoverable based on specific approval from the CPUC . The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the r egulatory assets for pension benefits ; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods presented. If the Utility determined that it is no longer probable th at regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. I f regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on its best estimate; to the extent there is a high degree of uncertainty in the Utility's forecast, it will record a provision based on the lower end of the range of possible losses. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors. The Utility recorded charges of $407 million in 2015 for estimated capital spending that is probable of disallowance related to the Penalty Decision. Management will continue to evaluate and estimate capital spending that may be probable of disallowance in future periods. These estimates are subject to adjustment based on the final 2015 GT&S rate case decision which is expected in 2016. The Utility also recorded $ 116 million and $ 196 million in 201 4 and 201 3 , respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. See " Enforcement and Litigation Matters " in Note 1 3 of the Notes to the Consolidated F inancial Statements in Item 8. Management will continue to periodically assess its safety-related capital costs and the related CPUC regulatory proceedings, and further charges could be required in future periods.

**Loss Contingencies**

***Environmental Remediation Liabilities***

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former manufactured gas plant sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses . Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2015 and 2014 , the Utility 's accruals for undiscounted gross environmental liabilities were $ 969 million and $ 954 million, respectively. The Utility's undiscounted future costs c ould increase to as much as $ 1.9 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Legal and Regulatory Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incur red for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range , unless an amount within the range is a better estimate than any other amount. T he assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred . (See "Enforcement and Litigation Matters" and "Legal and Regulatory Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**Asset Retirement Obligations**

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognize s a regulatory asset or liabilit y for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

To estimate its liability, the Utility uses a discounted cash flow model based upon significant est imates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2015 , the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $ 3.6 billion . Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the like lihood of an earlier start to decommissioning and cause an increase in the ARO. I f the inflation adjustment or discount rate increased 25 basis points, the result would be an immaterial impact to ARO.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees a s well as contributory postretirement health care and medical plans for eligible r etirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees . Adjustments to the pension and other benefit obligation are based on the d ifferences between actuarial assumptions and actual plan results . These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratem aking purposes are recorded as regulatory asset s or liabilit ies as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant a ctuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary . While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit oblig ations and future plan expenses.

I n establishing health care cost assumptions, PG&E Corporation and the Utility consider rec ent cost trends and projections from industry experts . This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2015 is 7.2 % , gradually decreasing to the u ltimate trend rate of 4 % in 2024 and beyond .

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed - income returns were projected based on real maturity and credit spreads added to a long-term inflat ion rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 6.1 % compares to a ten-year actual return of 7.8 % .

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 688 Aa-grade non-callable bonds at December 31, 2015 . This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2015 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2015 |
|---|---|---|---|
| Discount rate | (0.50) % | $ 119 | $ 1,227 |
| Rate of return on plan assets | (0.50) % | 70 | - |
| Rate of increase in compensation | 0.50 % | 59 | 285 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2015 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2015 |
|---|---|---|---|
| Health care cost trend rate | 0.50 % | $ 4 | $ 56 |
| Discount rate | (0.50) % | 4 | 123 |
| Rate of return on plan assets | (0.50) % | 10 | - |

**NEW ACCOUNTING PRONOUNCEMENTS**

See Note 2 of the Notes to the Consolidated Financial Statements.

**CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS**

This report contains forward-looking statements that reflect management's judgment and opinions and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated costs, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. These forward-looking statements are subject to various risks and uncertainties, the realization or resolution of which may be outside of management's control. Actual results could differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the 2015 GT&S rate case, the 2017 GRC, the TO rate cases, and other ratemaking and regulatory proceedings;

- the timing and outcomes of the federal criminal prosecution of the Utility, the pending CPUC investigation of the Utility's natural gas distribution record-keeping practices, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and the other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the timing and outcome of the CPUC's investigation of communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other ratemaking proceedings;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the criminal prosecution of the Utility, the state and federal investigations of natural gas incidents, matters relating to the indicted case, improper communications between the CPUC and the Utility; and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- whether the Utility can control its costs within the authorized levels of spending, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;

- the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

- the outcomes of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies, including the California State Water Resources Board and the California State Lands Commission, that may affect the Utility's ability to continue operating Diablo Canyon; and whether the Utility decides to resume its pursuit to renew the two Diablo Canyon NRC operating licenses, and if so, whether the licenses are renewed;

- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; and whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events;

- how the CPUC and the CARB implement state environmental laws relating to GHG , renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations, and whether the Utility is able to timely recover its associated investment costs;

- whether the Utility's climate change adaptation strategies are successful;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility's business strategy to address the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services is successful;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's information technology and operating systems;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the criminal prosecution, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see Item. 1A. Risk Factors above and our detailed discussion of these matters contained elsewhere in MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in MD&A in Item 7 and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **Operating Revenues** | | | |
| Electric | $ 13,657 | $ 13,658 | $ 12,494 |
| Natural gas | 3,176 | 3,432 | 3,104 |
| **Total operating revenues** | **16,833** | **17,090** | **15,598** |
| **Operating Expenses** | | | |
| Cost of electricity | 5,099 | 5,615 | 5,016 |
| Cost of natural gas | 663 | 954 | 968 |
| Operating and maintenance | 6,951 | 5,638 | 5,775 |
| Depreciation, amortization, and decommissioning | 2,612 | 2,433 | 2,077 |
| **Total operating expenses** | **15,325** | **14,640** | **13,836** |
| **Operating Income** | 1,508 | 2,450 | 1,762 |
| Interest income | 9 | 9 | 9 |
| Interest expense | (773) | (734) | (715) |
| Other income, net | 117 | 70 | 40 |
| **Income Before Income Taxes** | **861** | **1,795** | **1,096** |
| Income tax (benefit) provision | (27) | 345 | 268 |
| **Net Income** | **888** | **1,450** | **828** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 874** | **$ 1,436** | **$ 814** |
| **Weighted Average Common Shares Outstanding, Basic** | **484** | **468** | **444** |
| **Weighted Average Common Shares Outstanding, Diluted** | **487** | **470** | **445** |
| **Net Earnings Per Common Share, Basic** | **$ 1.81** | **$ 3.07** | **$ 1.83** |
| **Net Earnings Per Common Share, Diluted** | **$ 1.79** | **$ 3.06** | **$ 1.83** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E C orporation**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| **Net Income** | **$ 888** | **$ 1,450** | **$ 828** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $10, and $80, at respective dates) | (1) | (14) | 113 |
| Net change in investments (net of taxes of $12, $17, and $26 at respective dates) | (17) | (25) | 38 |
| **Total other comprehensive income (loss)** | **(18)** | **(39)** | **151** |
| **Comprehensive Income** | **870** | **1,411** | **979** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 856** | **$ 1,397** | **$ 965** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2015** | **2014** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 123 | $ 151 |
| Restricted cash | 234 | 298 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $54 and $66 at respective dates) | 1,106 | 960 |
| Accrued unbilled revenue | 855 | 776 |
| Regulatory balancing accounts | 1,760 | 2,266 |
| Other | 286 | 377 |
| Regulatory assets | 517 | 444 |
| Inventories | | |
| Gas stored underground and fuel oil | 126 | 172 |
| Materials and supplies | 313 | 304 |
| Income taxes receivable | 155 | 198 |
| Other | 347 | 443 |
| **Total current assets** | **5,822** | **6,389** |
| **Property, Plant, and Equipment** | | |
| Electric | 48,532 | 45,162 |
| Gas | 16,749 | 15,678 |
| Construction work in progress | 2,059 | 2,220 |
| Other | 2 | 2 |
| **Total property, plant, and equipment** | **67,342** | **63,062** |
| Accumulated depreciation | (20,619) | (19,121) |
| **Net property, plant, and equipment** | **46,723** | **43,941** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,029 | 6,322 |
| Nuclear decommissioning trusts | 2,470 | 2,421 |
| Income taxes receivable | 135 | 91 |
| Other | 1,160 | 963 |
| **Total other noncurrent assets** | **10,794** | **9,797** |
| **TOTAL ASSETS** | **$ 63,339** | **$ 60,127** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2015** | **2014** |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 1,019 | $ 633 |
| Long-term debt, classified as current | 160 | - |
| Accounts payable | | |
| Trade creditors | 1,414 | 1,244 |
| Regulatory balancing accounts | 715 | 1,090 |
| Other | 398 | 476 |
| Disputed claims and customer refunds | 454 | 434 |
| Interest payable | 206 | 197 |
| Other | 1,997 | 1,846 |
| **Total current liabilities** | **6,363** | **5,920** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 16,030 | 15,050 |
| Regulatory liabilities | 6,321 | 6,290 |
| Pension and other postretirement benefits | 2,622 | 2,561 |
| Asset retirement obligations | 3,643 | 3,575 |
| Deferred income taxes | 9,206 | 8,513 |
| Other | 2,326 | 2,218 |
| **Total noncurrent liabilities** | **40,148** | **38,207** |
| **Commitments and Contingencies (Note 13)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 492,025,443 and 475,913,404 shares outstanding at respective dates | 11,282 | 10,421 |
| Reinvested earnings | 5,301 | 5,316 |
| Accumulated other comprehensive (loss) income | (7) | 11 |
| **Total shareholders' equity** | **16,576** | **15,748** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **16,828** | **16,000** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 63,339** | **$ 60,127** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 888 | $ 1,450 | $ 828 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,612 | 2,433 | 2,077 |
| Allowance for equity funds used during construction | (107) | (100) | (101) |
| Deferred income taxes and tax credits, net | 693 | 690 | 1,075 |
| Disallowed capital expenditures | 407 | 116 | 196 |
| Other | 326 | 286 | 355 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (177) | 13 | (152) |
| Inventories | 37 | (22) | (10) |
| Accounts payable | (55) | (61) | 113 |
| Income taxes receivable/payable | 43 | 376 | (363) |
| Other current assets and liabilities | (315) | 205 | (469) |
| Regulatory assets, liabilities, and balancing accounts, net | (244) | (1,642) | (202) |
| Other noncurrent assets and liabilities | (355) | (67) | 80 |
| **Net cash provided by operating activities** | **3,753** | **3,677** | **3,427** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,173) | (4,833) | (5,207) |
| Decrease in restricted cash | 64 | 3 | 29 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,268 | 1,336 | 1,619 |
| Purchases of nuclear decommissioning trust investments | (1,392) | (1,334) | (1,604) |
| Other | 22 | 114 | 56 |
| **Net cash used in investing activities** | **(5,211)** | **(4,714)** | **(5,107)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings (repayments) under revolving credit facilities | - | (260) | 140 |
| Net issuances (repayments) of commercial paper, net of discount of $3, $2, and $2 at respective dates | 683 | (583) | 542 |
| Proceeds from issuance of short-term debt, net of issuance costs | - | 300 | - |
| Short-term debt matured | (300) | - | - |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $27, $17 and $18 at respective dates | 1,123 | 2,308 | 1,532 |
| Repayments of long-term debt | - | (889) | (861) |
| Common stock issued | 780 | 802 | 1,045 |
| Common stock dividends paid | (856) | (828) | (782) |
| Other | - | 42 | (41) |
| **Net cash provided by financing activities** | **1,430** | **892** | **1,575** |
| **Net change in cash and cash equivalents** | **(28)** | **(145)** | **(105)** |
| **Cash and cash equivalents at January 1** | **151** | **296** | **401** |
| **Cash and cash equivalents at December 31** | **$ 123** | **$ 151** | **$ 296** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | | | |
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | $ | (684) | $ | (633) | $ | (623) |
| Income taxes, net | | 77 | | 501 | | (41) |
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Common stock dividends declared but not yet paid | $ | 224 | $ | 217 | $ | 208 |
| Capital expenditures financed through accounts payable | | 440 | | 339 | | 322 |
| Noncash common stock issuances | | 21 | | 21 | | 22 |
| Terminated capital leases | | - | | 71 | | - |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Non controlling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2012** | **430,718,293** | **$ 8,428** | **$ 4,747** | **$ (101)** | **$ 13,074** | **$ 252** | **$ 13,326** |
| Net income | - | - | 828 | - | 828 | - | 828 |
| Other comprehensive income | - | - | - | 151 | 151 | - | 151 |
| Common stock issued, net | 25,952,131 | 1,067 | - | - | 1,067 | - | 1,067 |
| Stock-based compensation amortization | - | 56 | - | - | 56 | - | 56 |
| Common stock dividends declared | - | - | (819) | - | (819) | - | (819) |
| Tax expense from employee stock plans | - | (1) | - | - | (1) | - | (1) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2013** | **456,670,424** | **$ 9,550** | **$ 4,742** | **$ 50** | **$ 14,342** | **$ 252** | **$ 14,594** |
| Net income | - | - | 1,450 | - | 1,450 | - | 1,450 |
| Other comprehensive loss | - | - | - | (39) | (39) | - | (39) |
| Common stock issued, net | 19,242,980 | 823 | - | - | 823 | - | 823 |
| Stock-based compensation amortization | - | 65 | - | - | 65 | - | 65 |
| Common stock dividends declared | - | - | (862) | - | (862) | - | (862) |
| Tax expense from employee stock plans | - | (17) | - | - | (17) | - | (17) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2014** | **475,913,404** | **$ 10,421** | **$ 5,316** | **$ 11** | **$ 15,748** | **$ 252** | **$ 16,000** |
| Net income | - | - | 888 | - | 888 | - | 888 |
| Other comprehensive loss | - | - | - | (18) | (18) | - | (18) |
| Common stock issued, net | 16,112,039 | 801 | - | - | 801 | - | 801 |
| Stock-based compensation amortization | - | 66 | - | - | 66 | - | 66 |
| Common stock dividends declared | - | - | (889) | - | (889) | - | (889) |
| Tax expense from employee stock plans | - | (6) | - | - | (6) | - | (6) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **492,025,443** | **$ 11,282** | **$ 5,301** | **$ (7)** | **$ 16,576** | **$ 252** | **$ 16,828** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **Operating Revenues** | | | |
| Electric | $ 13,657 | $ 13,656 | $ 12,489 |
| Natural gas | 3,176 | 3,432 | 3,104 |
| **Total operating revenues** | **16,833** | **17,088** | **15,593** |
| **Operating Expenses** | | | |
| Cost of electricity | 5,099 | 5,615 | 5,016 |
| Cost of natural gas | 663 | 954 | 968 |
| Operating and maintenance | 6,949 | 5,635 | 5,742 |
| Depreciation, amortization, and decommissioning | 2,611 | 2,432 | 2,077 |
| **Total operating expenses** | **15,322** | **14,636** | **13,803** |
| **Operating Income** | 1,511 | 2,452 | 1,790 |
| Interest income | 8 | 8 | 8 |
| Interest expense | (763) | (720) | (690) |
| Other income, net | 87 | 77 | 84 |
| **Income Before Income Taxes** | **843** | **1,817** | **1,192** |
| Income tax (benefit) provision | (19) | 384 | 326 |
| **Net Income** | **862** | **1,433** | **866** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 848** | **$ 1,419** | **$ 852** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **Net Income** | **$ 862** | **$ 1,433** | **$ 866** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $1, $6, and $75, at respective dates) | (2) | (8) | 106 |
| **Total other comprehensive income (loss)** | **(2)** | **(8)** | **106** |
| **Comprehensive Income** | **$ 860** | **$ 1,425** | **$ 972** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2015** | **2014** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 59 | $ 55 |
| Restricted cash | 234 | 298 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $54 and $66 at respective dates) | 1,106 | 960 |
| Accrued unbilled revenue | 855 | 776 |
| Regulatory balancing accounts | 1,760 | 2,266 |
| Other | 284 | 375 |
| Regulatory assets | 517 | 444 |
| Inventories | | |
| Gas stored underground and fuel oil | 126 | 172 |
| Materials and supplies | 313 | 304 |
| Income taxes receivable | 130 | 168 |
| Other | 346 | 409 |
| **Total current assets** | **5,730** | **6,227** |
| **Property, Plant, and Equipment** | | |
| Electric | 48,532 | 45,162 |
| Gas | 16,749 | 15,678 |
| Construction work in progress | 2,059 | 2,220 |
| **Total property, plant, and equipment** | **67,340** | **63,060** |
| Accumulated depreciation | (20,617) | (19,120) |
| **Net property, plant, and equipment** | **46,723** | **43,940** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,029 | 6,322 |
| Nuclear decommissioning trusts | 2,470 | 2,421 |
| Income taxes receivable | 135 | 91 |
| Other | 1,053 | 864 |
| **Total other noncurrent assets** | **10,687** | **9,698** |
| **TOTAL ASSETS** | **$ 63,140** | **$ 59,865** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions , except share amounts )**

| | Balance at December 31, | |
|---|---|---|
| | **2015** | **2014** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 1,019 | $ 633 |
| Long-term debt, classified as current | 160 | - |
| Accounts payable | | |
| Trade creditors | 1,414 | 1,243 |
| Regulatory balancing accounts | 715 | 1,090 |
| Other | 418 | 444 |
| Disputed claims and customer refunds | 454 | 434 |
| Interest payable | 203 | 195 |
| Other | 1,750 | 1,604 |
| **Total current liabilities** | **6,133** | **5,643** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 15,680 | 14,700 |
| Regulatory liabilities | 6,321 | 6,290 |
| Pension and other postretirement benefits | 2,534 | 2,477 |
| Asset retirement obligations | 3,643 | 3,575 |
| Deferred income taxes | 9,487 | 8,773 |
| Other | 2,282 | 2,178 |
| **Total noncurrent liabilities** | **39,947** | **37,993** |
| **Commitments and Contingencies (Note 13)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 7,215 | 6,514 |
| Reinvested earnings | 8,262 | 8,130 |
| Accumulated other comprehensive income | 3 | 5 |
| **Total shareholders' equity** | **17,060** | **16,229** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 63,140** | **$ 59,865** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 862 | $ 1,433 | $ 866 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,611 | 2,432 | 2,077 |
| Allowance for equity funds used during construction | (107) | (100) | (101) |
| Deferred income taxes and tax credits, net | 714 | 731 | 1,103 |
| Disallowed capital expenditures | 407 | 116 | 196 |
| Other | 263 | 226 | 299 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (177) | 16 | (152) |
| Inventories | 37 | (22) | (10) |
| Accounts payable | (2) | (55) | 99 |
| Income taxes receivable/payable | 38 | 395 | (377) |
| Other current assets and liabilities | (342) | 155 | (404) |
| Regulatory assets, liabilities, and balancing accounts, net | (244) | (1,642) | (202) |
| Other noncurrent assets and liabilities | (340) | (66) | 22 |
| **Net cash provided by operating activities** | **3,720** | **3,619** | **3,416** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,173) | (4,833) | (5,207) |
| Decrease in restricted cash | 64 | 3 | 29 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,268 | 1,336 | 1,619 |
| Purchases of nuclear decommissioning trust investments | (1,392) | (1,334) | (1,604) |
| Other | 22 | 29 | 21 |
| **Net cash used in investing activities** | **(5,211)** | **(4,799)** | **(5,142)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $3, $2, and $2 at respective dates | 683 | (583) | 542 |
| Proceeds from issuance of short-term debt, net of issuance costs | - | 300 | - |
| Short-term debt matured | (300) | - | - |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $27, $14, and $18 at respective dates | 1,123 | 1,961 | 1,532 |
| Long-term debt matured or repurchased | - | (539) | (861) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (716) | (716) | (716) |
| Equity contribution from PG&E Corporation | 705 | 705 | 1,140 |
| Other | 14 | 56 | (26) |
| **Net cash provided by financing activities** | **1,495** | **1,170** | **1,597** |
| **Net change in cash and cash equivalents** | **4** | **(10)** | **(129)** |
| **Cash and cash equivalents at January 1** | **55** | **65** | **194** |
| **Cash and cash equivalents at December 31** | **$ 59** | **$ 55** | **$ 65** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | | | |
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | $ | (675) | $ | (618) | $ | (600) |
| Income taxes, net | | 77 | | 500 | | (62) |
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Capital expenditures financed through accounts payable | $ | 440 | $ | 339 | $ | 322 |
| Terminated capital leases | | - | | 71 | | - |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS ' EQUITY**
**(in millions)**

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2012** | **$ 258** | **$ 1,322** | **$ 4,682** | **$ 7,291** | **$ (93)** | **$ 13,460** |
| Net income | - | - | - | 866 | - | 866 |
| Other comprehensive income | - | - | - | - | 106 | 106 |
| Equity contribution | - | - | 1,140 | - | - | 1,140 |
| Tax expense from employee stock plans | - | - | (1) | - | - | (1) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2013** | **$ 258** | **$ 1,322** | **$ 5,821** | **$ 7,427** | **$ 13** | **$ 14,841** |
| Net income | - | - | - | 1,433 | - | 1,433 |
| Other comprehensive loss | - | - | - | - | (8) | (8) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (12) | - | - | (12) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2014** | **$ 258** | **$ 1,322** | **$ 6,514** | **$ 8,130** | **$ 5** | **$ 16,229** |
| Net income | - | - | - | 862 | - | 862 |
| Other comprehensive loss | - | - | - | - | (2) | (2) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (4) | - | - | (4) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **$ 258** | **$ 1,322** | **$ 7,215** | **$ 8,262** | **$ 3** | **$ 17,060** |

See accompanying Notes to the Consolidated Financial Statements.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's c onsolidated f inancial s tatements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's c onsolidated f inancial s tatements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying c onsolidated f inancial s tatements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP require s the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilitie s. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, ARO s, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the c onsolidated f inancial s tatements are appropriate and reasonable. Actual results could differ materially from those estimates.

**NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**Regulation and Regulated Operations**

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover “revenue requirements” that have been authorized by the CPUC or the FERC based on the Utility’s cost of providing service. T he Utility’s ability to recover a significant portion of its authorized revenue requirements through rates is generally independent, or “decoupled,” from the volume of the Utility’s electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. A mounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

The Utility also records a regulatory balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund. In addition, t he Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs , t o the extent that these differences are probable of recovery or refund . These differences have no impact on net income. (S ee “Revenue Recognition” below. )

Management continues to believe the use of regulatory accounting is applicable a nd that all regulatory assets and liabilitie s are recoverable or refundable. To the extent that portions of the Utility’s operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

**Revenue Recognition**

The Utility recognizes revenues when electricity and natural gas services are delivered . The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

The CPUC authorizes most of the Utility’s revenues in the Utility’s GRC and its GT&S rate cases, which generally occur every three years. T he Utility’s ability to recover r evenue requirements authorized by the CPUC in these rates cases is independent, or “decoupled” from the volume of the Utility’s sales of electricity and natural gas services. The U tility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, revenue is recognized ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general , the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility’s revenue requirements in periodic (often annual) TO rate cases. The Utility’s ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility’s electricity sales, and revenue is recognized only for amounts billed and unbilled.

**C ash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

**Restricted Cash**

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See " Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 below .)

**Allowance for Doubtful Accounts Receivable**

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectable customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables , current economic conditions, and assessment of customer collectability.

**Inventories**

Inventories are carried at weighted- average cost and include natural gas stored underground as well as materials and supplies . Natural gas stored underground is recorded to inventory when injected and then expensed as the gas is withdrawn for distribut ion to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and expensed or capitalized to plant, as appropriate, when consumed or installed.

**Emission Allowances**

The Utility purchases GHG emission allowances to satisfy its compliance obligations. Associated costs are recorded as inventory and included in current assets – other and other noncurrent assets – other on the Consolidated Balance Sheets. Costs are carried at weighted-average and are recoverable through rates.

**Property, Plant, and Equipment**

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value . Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

| | Estimated Useful | Balance at December 31, | |
|---|---|---|---|
| **(in millions, except estimated useful lives)** | **Lives (years)** | **2015** | **2014** |
| Electricity generating facilities [1] | 5 to 100 | $ 9,860 | $ 9,374 |
| Electricity distribution facilities | 15 to 55 | 28,476 | 26,633 |
| Electricity transmission facilities | 15 to 75 | 10,196 | 9,155 |
| Natural gas distribution facilities | 5 to 60 | 10,397 | 9,741 |
| Natural gas transportation and storage facilities | 5 to 65 | 6,352 | 5,937 |
| Construction work in progress | | 2,059 | 2,220 |
| **Total property, plant, and equipment** | | **67,340** | **63,060** |
| Accumulated depreciation | | (20,617) | (19,120) |
| **Net property, plant, and equipment** | | **$ 46,723** | **$ 43,940** |

[1] Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted- average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 13 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's co mposite depreciation rates were 3.80 % in 2015 , 3.77 % in 2014 , and 3.51 % in 2013 . The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC represents the estimated cost s of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $ 48 million and $ 107 million during 2015 , $ 45 million and $ 100 million during 2014 , and $ 47 million and $ 101 million during 2013 .

**Asset Retirement Obligations**

The following table summarizes the changes in ARO liability during 2015 and 2014 , including nuclear decommissioning obligations :

| **(in millions)** | **2015** | **2014** |
|---|---|---|
| ARO liability at beginning of year | $ 3,575 | $ 3,538 |
| Revision in estimated cash flows | 13 | (16) |
| Accretion | 169 | 163 |
| Liabilities settled | (114) | (110) |
| **ARO liability at end of year** | **$ 3,643** | **$ 3,575** |

The Utility has not recorded a liability related to certain ARO's for assets that are expe cted to operate in perpetuity. As t he Utility cannot estimate a settlement date or range of potential settlement dates for these assets , reasonable estimate s of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities associated with substations, photovoltaic facilities, and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration or land to the conditions under certain agreements.

*Nuclear Decommissioning Obligation*

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment.

The Utility adjusts its nuclear decommissioning obligation to reflect changes in the estimated costs of decommissioning its nuclear power facilities and records this as an adjustment to the ARO liability on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $ 2.5 billion at December 31, 2015 and 2014 . The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $ 3.5 billion at December 31, 2015 and 2014 (or $ 6.1 billion in future dollars). These estimates are based on the 2012 decommissioning cost studies, prepared in accordance with CPUC requirements.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. The Utility recorded charges of $407 million in 2015 for estimated capital spending that is probable of disallowance related to the Penalty Decision and $116 million and $196 million in 2014 and 2013 , respectively, for PSEP capital costs that are expected to exceed the CPUC's authorized levels or that are specifically disallowed. (See "Enforcement and Litigation Matters" in Note 13 below).

**Nuclear Decommissioning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facilit y from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC .

The Utility classifies its investments held in the nuclear decommissioning trust s as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIE s at December 31, 2015, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement , analyzed the variability in the VIE's gross margin , and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. T he Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs . Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2015 , it did not consolidate any of them .

**Other Accounting Policies**

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives " in Note 9, "Fair Value Measurements" in Note 10 , and "Contingencies and Commitments" in Note 13 of the Notes to the Consolidated Financial Statements.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2015 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| Beginning balance | $ (21) | $ 15 | $ 17 | $ 11 |
| **Other comprehensive income before reclassifications:** | | | | |
| Unrecognized net actuarial loss (net of taxes of $51, $21, and $0, respectively) | (76) | (31) | - | (107) |
| Regulatory account transfer (net of taxes of $51, $21, and $0, respectively) | 73 | 31 | - | 104 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $7, $8, and $0, respectively) [1] | 8 | 11 | - | 19 |
| Amortization of net actuarial loss (net of taxes of $4, $1, and $0, respectively) [1] | 6 | 3 | - | 9 |
| Regulatory account transfer (net of taxes of $10, $9, and $0, respectively) [1] | (13) | (13) | - | (26) |
| Realized gain on investments (net of taxes of $0, $0, and $12, respectively) | - | - | (17) | (17) |
| **Net current period other comprehensive loss** | **(2)** | **1** | **(17)** | **(18)** |
| **Ending balance** | **$ (23)** | **$ 16** | **$ -** | **$ (7)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2014 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| Beginning balance | $ (7) | $ 15 | $ 42 | $ 50 |
| **Other comprehensive income before reclassifications:** | | | | |
| Change in investments (net of taxes of $0, $0, and $4, respectively) | - | - | 5 | 5 |
| Unrecognized net actuarial loss (net of taxes of $404, $19, and $0, respectively) | (588) | (28) | - | (616) |
| Unrecognized prior service cost (net of taxes of $0, $0, and $0, respectively) | 1 | - | - | 1 |
| Regulatory account transfer (net of taxes of $394, $19, and $0, respectively) | 573 | 28 | - | 601 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $8, $9, and $0, respectively) [1] | 12 | 14 | - | 26 |
| Amortization of net actuarial loss (net of taxes of $1, $1, and $0, respectively) [1] | 1 | 1 | - | 2 |
| Regulatory account transfer (net of taxes of $9, $10, and $0, respectively) [1] | (13) | (15) | - | (28) |
| Realized gain on investments (net of taxes of $0, $0, and $20, respectively) | - | - | (30) | (30) |
| **Net current period other comprehensive loss** | **(14)** | **-** | **(25)** | **(39)** |
| **Ending balance** | **$ (21)** | **$ 15** | **$ 17** | **$ 11** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**New Accounting Pronouncements**

***Recognition and Measurement of Financial Assets and Financial Liabilities***

In January 2016, the FASB issued ASU No. 2016 -0 1 , *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* , which amends guidance to help improve the recognition and measurement of financial instruments . The ASU will be effective for PG&E Corporation and the Utility on January 1, 201 8 . PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

***Balance Sheet Classification of Deferred Taxes***

In November 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* , which amends existing guidance on the presentation of deferred income tax assets and liabilities. The amendments in the ASU require that all deferred tax liabilities and assets be classified as noncurrent on the balance sheet. This ASU w ill be effective for PG&E Corporation and the Utility on January 1, 2017, with earlier adoption permitted. PG&E Corporation and the Utility have implemented this standard as of the year end ed December 31, 2015 on a prospective basis and the prior periods have not been retrospectively adjusted.

***Fair Value Measurement***

In May 2015, the F ASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* , which removes the requirement to categorize within the fair value hierarchy all investments measured using net asset value per share as a practical expedient. The ASU became effective for PG&E Corporation and the Utility on January 1, 2016 . This standard will be adopted for related disclosures in the first quarter of 2016 and will not have an impact on the conso lidated financial statements.

***Accounting for Fees Paid in a Cloud Computing Arrangement***

In April 2015, the F ASB issued ASU No. 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement ,* which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. The ASU became effective for PG&E Corporation and the Utility on January 1, 2016. P G&E Corporation and the Utility h ave determined that this ASU will not impact their consolidated financial statements and related disclosures and will adopt this standard starting in the first quarter of 2016.

***Presentation of Debt Issuance Costs***

In April 2015, the F ASB issued ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ,* which amends existing presentation of debt issuance costs. PG&E Corporation and the Utility currently disclose debt issuance costs in current assets – other and noncurrent assets – other. The amendments in this ASU, that became effecti ve for PG&E Corporation and the Utility on J anuary 1, 2016, require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility will adopt this standard in the first quarter of 2016 and do not expect the reclassification to have a material impact on their conso lidated financial statements.

***Revenue Recognition Standard***

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which amends existing revenue recognition guidance . In August 2015 *, the FASB issued* ASU No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* , deferring the effective date of this amendment for PG&E Corporation and the Utility by one year to January 1, 2018 , with early adoption permitted as of the original effective date of January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

## NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

### Regulatory Assets

Long-term regulatory assets are comprised of the following:

| (in millions) | Balance at December 31, 2015 | Balance at December 31, 2014 | Recovery Period |
|---|---|---|---|
| Pension benefits [1] | $ 2,414 | $ 2,347 | Indefinitely [4] |
| Deferred income taxes [1] | 3,054 | 2,390 | 47 years |
| Utility retained generation [2] | 411 | 456 | 10 years |
| Environmental compliance costs [1] | 748 | 717 | 32 years |
| Price risk management [1] | 138 | 127 | 10 years |
| Electromechanical meters [3] | - | 70 | - |
| Unamortized loss, net of gain, on reacquired debt [1] | 94 | 113 | 11 years |
| Other | 170 | 102 | Various |
| **Total long-term regulatory assets** | **$ 7,029** | **$ 6,322** | |

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recog nized in accordance with GAAP.
(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.
(3) Represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices. As of December 31, 2015, the remaining balance of $70 million is included in current regulatory assets on the Consolidated Balance Sheets.
(4) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, t he Utility expects to continuously recover pension benefits.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, regulatory assets for electromechanical meters, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

### Regulatory Liabilities

#### *Current Regulatory Liabilities*

At December 31, 2015 and 2014, the Utility had current regulatory liabilities of $676 million and $261 million, respectively. At December 31, 2015 , the current regulatory liabilities consisted primarily of a $400 million bill credit to the Utility's natural gas customers resulting from the Penalty Decision. (See Note 13 below.) Current regulatory liabilities are included within current liabilities-other in the Consolidated Balance Sheets.

***Long -Term Regulatory Liabilities***

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Balance at December 31, 2015 | | Balance at December 31, 2014 | |
|---|---|---|---|---|
| Cost of removal obligations [1] | $ | 4,605 | $ | 4,211 |
| Recoveries in excess of AROs [2] | | 631 | | 754 |
| Public purpose programs [3] | | 600 | | 701 |
| Other | | 485 | | 624 |
| **Total long-term regulatory liabilities** | **$** | **6,321** | **$** | **6,290** |

[1] Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.
[2] Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the se nuclear decommissioning trust investments. (See Note 10 below.)
[3] Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

**Regulatory Balancing Accounts**

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets. These differences do not have an impact on net income . Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and cu stomer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

| (in millions) | Receivable Balance at December 31, 2015 | | Receivable Balance at December 31, 2014 | |
|---|---|---|---|---|
| Electric distribution | $ | 380 | $ | 344 |
| Utility generation | | 122 | | 261 |
| Gas distribution | | 493 | | 566 |
| Energy procurement | | 262 | | 608 |
| Public purpose programs | | 155 | | 109 |
| Other | | 348 | | 378 |
| **Total regulatory balancing accounts receivable** | **$** | **1,760** | **$** | **2,266** |

| (in millions) | Payable Balance at December 31, 2015 | | Payable Balance at December 31, 2014 | |
|---|---|---|---|---|
| Energy procurement | $ | 112 | $ | 188 |
| Public purpose programs | | 244 | | 154 |
| Other | | 359 | | 748 |
| **Total regulatory balancing accounts payable** | **$** | **715** | **$** | **1,090** |

The electric distribution, utility generation, and gas distribution balancing accounts track the collection of revenue requirements approved in the GRC. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. P ublic purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency and low income energy efficiency.

## NOTE 4: DEBT

### Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

| (in millions) | December 31, 2015 | December 31, 2014 |
|---|---|---|
| **PG&E Corporation** | | |
| Senior notes, 2.40%, due 2019 | 350 | 350 |
| **Total PG&E Corporation long-term debt** | **350** | **350** |
| **Utility** | | |
| Senior notes: | | |
| 5.625% due 2017 | 700 | 700 |
| 8.25% due 2018 | 800 | 800 |
| 3.50% due 2020 | 800 | 800 |
| 4.25% due 2021 | 300 | 300 |
| 3.25% due 2021 | 250 | 250 |
| 2.45% due 2022 | 400 | 400 |
| 3.25% due 2023 | 375 | 375 |
| 3.85% due 2023 | 300 | 300 |
| 3.40% due 2024 | 350 | 350 |
| 3.75% due 2024 | 450 | 450 |
| 3.50% due 2025 | 600 | - |
| 6.05% due 2034 | 3,000 | 3,000 |
| 5.80% due 2037 | 950 | 950 |
| 6.35% due 2038 | 400 | 400 |
| 6.25% due 2039 | 550 | 550 |
| 5.40% due 2040 | 800 | 800 |
| 4.50% due 2041 | 250 | 250 |
| 4.45% due 2042 | 400 | 400 |
| 3.75% due 2042 | 350 | 350 |
| 4.60% due 2043 | 375 | 375 |
| 5.125% due 2043 | 500 | 500 |
| 4.75% due 2044 | 675 | 675 |
| 4.30% due 2045 | 600 | 500 |
| 4.25% due 2046 | 450 | - |
| Unamortized discount, net of premium | (53) | (43) |
| **Total senior notes, net of current portion** | **14,572** | **13,432** |
| Pollution control bonds: | | |
| Series 1996 C, E, F, 1997 B, variable rates (1), due 2026 (2) | 614 | 614 |
| Series 2004 A-D, 4.75%, due 2023 (3) | 345 | 345 |
| Series 2009 A-D, variable rates (1), due 2016 and 2026 (4) | 309 | 309 |
| Less: current portion | (160) | - |
| **Total pollution control bonds** | **1,108** | **1,268** |
| **Total Utility long-term debt, net of current portion** | **15,680** | **14,700** |
| **Total consolidated long-term debt, net of current portion** | **$ 16,030** | **$ 15,050** |

(1) At December 31 , 2015 , interest rates on these bonds were 0.01 % .
(2) Each series of these bonds is supported by a separate letter of credit . In December 2015, the letters of credit were extended to December 1, 20 20 . Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.
(3) The Utility has obtained credit support from an insurance company for these bonds.
(4) Each series of these bonds is supported by a separate direct-pay letter of credit . Series C and D letters of credit expire on December 3, 2016 to coincide with the maturity of the underlying bonds. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant . In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding . Except for components that may have been abandoned in place or disposed of as scrap or that are permanently non-operational, t he Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper program s at December 31, 2015 :

| (in millions) | Termination Date | Credit Facility Limit | Letters of Credit Outstanding | Commercial Paper Outstanding | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2020 | $ 300 (1) | $ - | $ - | $ 300 |
| Utility | April 2020 | 3,000 (2) | 33 | 1,019 | 1,948 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 33** | **$ 1,019** | **$ 2,248** |

(1) Includes a $ 50 million lender commitment to the letter of credit sublimit s and a $100 million commitment for "swingline" loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $ 50 0 m illion lender commitment to the letter of credit sublimit s and a $ 75 million commitment for swingline loans.

For the year ended December 31, 2015 , PG&E Corporation's average outstanding commercial paper balance was $ 64 million and the maximum outstanding balance during the year was $ 128 million. For 2015 , the Utility's average outstanding commercial paper balance was $ 678 million and the maximum outstanding balance during the year was $ 1.5 billion. There were no bank borrowings for both PG&E Corporation and t he U tility in 2015 .

***Revolving Credit Facilities***

On April 27, 2015, PG&E Corporation and the Utility amended and restated their respective $300 million and $3.0 billion revolving credit facilities . The amendments and restatements extended the termination dates of the credit facilities from April 1, 2019 to April 27, 2020, reduced the amount of lender commitments to the letter of credit sublimits from $100 million to $50 million for PG&E Corporation's credit facility and from $1.0 billion to $500 m illion for the Utility's credit facility, and reduced the swingline commitment on the Utility's credit facility from $300 million to $75 million . PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for additional periods.

Borrowings under each amended and restated credit agreement (other than swing line loans) will bear interest based, at each borrower's election, on (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The applicable margin for LIBOR loans will range between 0.9% and 1.475% under PG&E Corporation's amended and restated credit agreement and between 0.8% and 1.275% under the Utility's amended and restated credit agreement. The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation's amended and restated credit agreement and between 0% and 0.275% under the Utility's amended and restated credit agreement. In addition, the facility fee under PG&E Corporation's and the Utility's amended and restated credit agreements will range between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the respective revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter . PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

***Commercial Paper Program s***

The borrowings from PG&E Corporation and the Utility 's commercial paper programs are used primarily to fund temporary financing needs . On July 2, 2015, the Utility increased the commercial paper program limit from $1.75 billion to $2.5 billion. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation's and the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. For 2015 , the average yield on outstanding PG&E Corporation and Utility commercial paper was 0.38 % and 0.42 % , respectively .

***Other Short-term Borrowings***

On May 11, 2015 , $ 300 million principal amount of the Utility's Floating Rate Senior Notes matured.

**Repayment Schedule**

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2015 are reflected in the table below:

| (in millions, except interest rates) | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest rate | - | - | - | 2.40 % | - | - | 2.40 % |
| Fixed rate obligations | $ - | $ - | $ - | $ 350 | $ - | $ - | $ 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | - | 5.63 % | 8.25 % | - | 3.50 % | 4.91 % | 5.05 % |
| Fixed rate obligations | $ - | $ 700 | $ 800 | $ - | $ 800 | $ 12,670 | $ 14,970 |
| Variable interest rate as of December 31, 2015 | 0.01 % | - | - | 0.01 % | 0.01 % | - | 0.01 % |
| Variable rate obligations [1] | $ 160 | $ - | $ - | $ 149 | $ 614 | $ - | $ 923 |
| **Total consolidated debt** | **$ 160** | **$ 700** | **$ 800** | **$ 499** | **$ 1,414** | **$ 12,670** | **$ 16,243** |

[1] These bonds, due in 2016 and 2026, are backed by separate letters of credit that expire on December 3, 2016, June 5, 2019, or December 1, 2020.

**NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION**

PG&E Corporation had 492,025,443 shares of common stock outstanding at December 31, 2015 . PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2015 .

In February 2015, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $ 500 million. During 2015 , PG&E Corporation sold 1.4 million shares under this agreement for cash proceeds of $ 74 million, net of commissions paid of $ 1 million.

In August 2015 , PG&E Corporation sold 6.8 million shares of its common stock in an underwritten public offering for cash proceeds of $352 million, net of fees .

In addition, during 2015 , PG&E Corporation sold 7.9 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $ 354 million .

**Dividends**

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. For 201 5 , the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of $0.455 per share.

Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on a weighted average over four years. PG&E Corporation and the Utility are in compliance with these restrictions. At December 31, 2015, the Utility had restricted net assets of $ 15.2 billion and was limited to $ 110 million of additional common stock dividends it could pay to PG&E Corporation.

**Long-Term Incentive Plan**

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, restricted stock units , performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards . In May 2014, the 2006 LTIP was terminated and the 2014 LTIP became effective. A maximum of 1 7 million shares o f PG&E Corporation common stock (subject to certain adjustment s ) has been reserved for issuance under the 20 14 LTIP, of which 15,674,803 shares were available for future award s at December 31, 2015 .

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2015 , 2014 , and 2013 :

| **(in millions)** | **2015** | | **2014** | | **2013** | |
|---|---|---|---|---|---|---|
| Restricted stock units | $ | 47 | $ | 42 | $ | 36 |
| Performance shares | | 46 | | 36 | | 28 |
| Total compensation expense (pre-tax) | **$** | **93** | **$** | **78** | **$** | **64** |
| Total compensation expense (after-tax) | **$** | **55** | **$** | **47** | **$** | **38** |

The amount of s hare-based compensation costs capitalized during 2015 , 2014 , and 2013 was immaterial . There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

Prior to 2014, restricted stock units generally vest ed over four year s in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. R estricted stock units granted in 2014 and 2015 generally vest equally over three year s . Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value . The weighted average grant-date fair value for restricted stock units granted during 2015 , 2014 , and 2013 was $ 53.30 , $ 43.76 , and $4 2.92 , respectively. The total fair value of restricted stock units that vested during 2015 , 2014 , and 2013 was $ 57 million, $ 34 million, and $30 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. As of December 31, 2015 , $ 45 mil lion of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remai ning weighted average period of 1.48 years.

The following table summarizes restricted stock unit activity for 2015 :

| | Number of Restricted Stock Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 2,538,357 | $ 43.39 |
| Granted | 820,834 | 53.30 |
| Vested | (1,304,150) | 43.51 |
| Forfeited | (82,142) | 45.63 |
| Nonvested at December 31 | **1,972,899** | $ 47.33 |

***Performance Shares***

Performance shares generally will vest three year s after the grant date. Upon vesting, performance shares are settled in shares of common stock based on PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period. Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled .

Compensation expense attributable to p erformance share is generally recognized rat e ably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model. The weighted average grant-date fair value for performance shares granted during 2015 , 2014 , and 2013 was $ 68.27 , $ 51.81 , and $33.45 respective ly. There was no tax benefit associated with performance shares during each of these periods . As of December 31, 2015 , $ 36 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.45 ye ar s .

The following table summarizes activity for performance shares in 2015 :

| | Number of Performance Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,693,939 | $ 42.37 |
| Granted | 669,519 | 68.27 |
| Vested | (421,262) | 33.57 |
| Forfeited (1) | (491,584) | 35.56 |
| Nonvested at December 31 | **1,450,612** | $ 59.24 |

(1) Includes performance shares that expired with 50% value as a result of total shareholder return results.

**NOTE 6: PREFERRED STOCK**

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $ 100 par value preferred stock , which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding .

The Utility has authorized 75 million shares of $ 25 par value preferred stock and 10 million shares of $ 100 par value preferred stock. At December 31, 2015 and December 31, 2014, the Utility's preferred stock outstanding included $ 145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $ 113 million of shares with interest rates between 4.36% and 5% that are redeemable between $ 25.75 and $ 27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

At December 31, 2015 , annual dividends on the Utility's nonredeemable preferred stock ranged from $ 1.25 to $ 1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2015 , annual dividends on redeemable preferred stock ranged from $ 1.09 to $ 1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. T he Utility paid $ 14 million of dividends on preferred stock in each of 2015 , 2014, and 2013.

**NOTE 7: EARNINGS PER SHARE**

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2015 , 2014 , and 2013 .

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2015** | **2014** | **2013** |
| **Income available for common shareholders** | $ 874 | $ 1,436 | $ 814 |
| **Weighted average common shares outstanding, basic** | 484 | 468 | 444 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | 3 | 2 | 1 |
| **Weighted average common share outstanding, diluted** | 487 | 470 | 445 |
| **Total earnings per common share, diluted** | **$ 1.79** | **$ 3.06** | **$ 1.83** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

**NOTE 8: INCOME TAXES**

PG&E Corporation and the Utility use the liability method of accounting for income taxes. The i ncome tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. T he tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, t he difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance in the financial statements represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows :

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| (in millions) | 2015 | 2014 | 2013 | 2015 | 2014 | 2013 |
| Current: | | | | | | |
| Federal | $ (89) | $ (84) | $ (218) | $ (88) | $ (84) | $ (222) |
| State | 11 | (41) | (26) | 6 | (29) | (23) |
| Deferred: | | | | | | |
| Federal | 131 | 396 | 552 | 136 | 426 | 604 |
| State | (76) | 78 | (35) | (69) | 75 | (28) |
| Tax credits | (4) | (4) | (5) | (4) | (4) | (5) |
| **Income tax provision** | **$ (27)** | **$ 345** | **$ 268** | **$ (19)** | **$ 384** | **$ 326** |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| (in millions) | 2015 | 2014 | 2015 | 2014 |
| **Deferred income tax assets:** | | | | |
| Customer advances for construction | $ 69 | $ 88 | $ 69 | $ 88 |
| Environmental reserve | 85 | 111 | 85 | 111 |
| Compensation and benefits | 219 | 244 | 145 | 173 |
| Tax carryforward s | 1, 703 | 1,177 | 1, 462 | 946 |
| Greenhouse gas allowances | 340 | 56 | 340 | 56 |
| Other | 44 | 74 | 61 | 1 00 |
| **Total deferred income tax assets** | **$ 2,460** | **$ 1,750** | **$ 2,162** | **$ 1,474** |
| **Deferred income tax liabilities:** | | | | |
| Regulatory balancing accounts | $ 691 | $ 512 | $ 691 | $ 512 |
| Property related basis differences | 9, 656 | 8,683 | 9, 638 | 8,666 |
| Income tax regulatory asset [(1)] | 1,244 | 974 | 1,245 | 974 |
| Other | 75 | 88 | 7 5 | 86 |
| **Total deferred income tax liabilities** | **$ 11, 666** | **$ 10,257** | **$ 11, 649** | **$ 10,238** |
| **Total net deferred income tax liabilities** | **$ 9,206** | **$ 8,507** | **$ 9,487** | **$ 8,764** |
| **Classification of net deferred income tax liabilities:** | | | | |
| Included in current liabilities (assets) | $ - | $ (6) | $ - | $ (9) |
| Included in noncurrent liabilities | 9,206 | 8,513 | 9,487 | 8,773 |
| **Total net deferred income tax liabilities** | **$ 9,206** | **$ 8,507** | **$ 9,487** | **$ 8,764** |

[(1)] Represents the deferred income tax component of the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. (See Note 3 above.)

The following table reconciles income tax expense at the federal statutory rate to the income tax provision :

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| | 2015 | 2014 | 2013 | 2015 | 2014 | 2013 |
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) [1] | (4.9) | 1.4 | (3.1) | (4.8) | 1.6 | (2.2) |
| Effect of regulatory treatment of fixed asset differences [2] | (33.6) | (15.0) | (4.2) | (33.7) | (14.7) | (3.8) |
| Tax credits | (1.3) | (0.7) | (0.4) | (1.3) | (0.7) | (0.4) |
| Benefit of loss carryback | (1.5) | (0.8) | (1.1) | (1.5) | (0.8) | (1.0) |
| Non deductible penalties [3] | 4.3 | 0.3 | 0.8 | 4.3 | 0.3 | 0.7 |
| Other, net | (1.1) | (0.8) | (2.2) | (0.2) | 0.4 | (0.9) |
| **Effective tax rate** | **(3.1) %** | **19.4 %** | **24.8 %** | **(2.2) %** | **21.1 %** | **27.4 %** |

[1] Includes the effect of state flow-through rate making treatment. In 2015, amounts include an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.
[2] I nclude s the effect of federal flow-through ratemaking treatment for certain property-related costs in 2015 and 2014 as authorized by the 2014 GRC decision. Amounts are impacted by the level of income before income taxes.
[3] Represen ts the effect s of non-tax deductible fines and penalties associated with the Penalty Decision . ( For more information about the Penalty Decision see Note 13 below . )

***Unrecognized tax benefits***

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| **(in millions)** | **2015** | **2014** | **2013** | **2015** | **2014** | **2013** |
| **Balance at beginning of year** | $ 713 | $ 666 | $ 581 | $ 707 | $ 660 | $ 575 |
| Additions for tax position taken during a prior year | 40 | 7 | 12 | 40 | 7 | 12 |
| Reductions for tax position taken during a prior year | (349) | (9) | (6) | (349) | (9) | (6) |
| Additions for tax position taken during the current year | 64 | 61 | 79 | 64 | 61 | 79 |
| Settlements | - | (12) | - | - | (12) | - |
| **Balance at end of year** | **$ 468** | **$ 713** | **$ 666** | **$ 462** | **$ 707** | **$ 660** |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2015 for PG &E Corporation and the Utility was $ 50 million .

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2015, it is reasonably possible that unrecognized tax benefits will decrease by approximately $ 60 million within the next 12 months.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For t he years ended December 31, 2015 , 2014, and 201 3 , these amounts were immaterial.

***IRS settlements***

PG&E Corporation participated in the Compliance Assurance Process in 2015, a real-time IRS audit intended to expedite resolution of tax matters. The Compliance Assurance Process audit culminates with a letter from the IRS indicating its acceptance of the return.

PG&E Corporation's tax returns have been accepted through 2014 except for a few matters, the most significant of which relates to deductible repair costs. In December 2015, PG&E Corporation reached an agreement with the IRS on deductible repair costs for the 2011 tax year, subject to approval by the Joint Committee on Taxation. Deductible repair costs will continue to be subject to examination by the IRS for subsequent years. The IRS is expected to issue guidance in 2016 that clarifies which repair costs are deductible for the natural gas transmission and distribution businesses. T ax years after 2004 remain subject to examination by the state of California.

***Carryforwards***

The following table describes PG&E Corporation's operating loss and tax credit carryforward balances :

| (in millions) | December 31, 2015 | | Expiration Year |
|---|---|---|---|
| **Federal:** | | | |
| Net operating loss carryforward | $ | 4,856 | 2029 - 2035 |
| Tax credit carryforward | | 110 | 2029 - 2035 |
| Charitable contribution loss carryforward | | 178 | 2017 - 2020 |
| | | | |
| **State:** | | | |
| Net operating loss carryforward | $ | 80 | 2033 - 2034 |
| Tax credit carryforward | | 59 | Various |
| Charitable contribution loss carryforward | | 119 | 2019 - 2020 |

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating loss es, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 201 5 for these tax attributes. As of December 31, 2015 , PG&E Corporation had approximately $ 29 million of f ederal net operating loss carry forwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

**NOTE 9: DERIVATIVES**

**Use of Derivative Instruments**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include forward contracts, swaps, futures, options, and CRRs.

Derivatives are pres ented in the Utility's Consolidated Balance Sheets on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives as long as the current ratemaking mechanism remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

**Volume of Derivative Activity**

At December 31, 2015 and 2014 , respectively , the volume s of the Utility's outstanding derivatives w ere as follows:

| | | Contract Volume | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **2015** | **2014** |
| Natural Gas [1] (MMBtus [2] ) | Forwards and Swaps | 333,091,813 | 308,130,101 |
| | Options | 111,550,004 | 164,418,002 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 3,663,512 | 5,346,787 |
| | Congestion Revenue Rights [3] | 216,383,389 | 224,124,341 |

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

**Presentation of Derivative Instruments in the Financial Statements**

At December 31, 2015 , the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 97 | $ (4) | $ 25 | $ 118 |
| Other noncurrent assets – other | 172 | (2) | - | 170 |
| Current liabilities – other | (102) | 4 | 44 | (54) |
| Noncurrent liabilities – other | (140) | 2 | 21 | (117) |
| **Total commodity risk** | **$ 27** | **$ -** | **$ 90** | **$ 117** |

At December 31, 2014 , the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 73 | $ (4) | $ 19 | $ 88 |
| Other noncurrent assets – other | 178 | (13) | - | 165 |
| Current liabilities – other | (78) | 4 | 26 | (48) |
| Noncurrent liabilities – other | (140) | 13 | 9 | (118) |
| **Total commodity risk** | **$ 33** | **$ -** | **$ 54** | **$ 87** |

Gains and losses associated with price risk management activities were recorded as follows:

| | Commodity Risk | | |
|---|---|---|---|
| | For the year ended December 31, | | |
| **(in millions)** | **2015** | **2014** | **2013** |
| Unrealized gain/(loss) - regulatory assets and liabilities (1) | $ (6) | $ 124 | $ 238 |
| Realized loss - cost of electricity (2) | (14) | (83) | (178) |
| Realized loss - cost of natural gas (2) | (10) | (8) | (22) |
| **Total commodity risk** | **$ (30)** | **$ 33** | **$ 38** |

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2015 , the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

T he additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2015** | **2014** |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (2) | $ (47) |
| Related derivatives in an asset position | - | - |
| Collateral posting in the normal course of business related to these derivatives | - | 44 |
| **Net position of derivative contracts/additional collateral posting requirements (1)** | **$ (2)** | **$ (3)** |

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's cre dit risk-related contingencies.

**NOTE 10: FAIR VALUE MEASUREMENTS**

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments , and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value :

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts and other investments are held by PG&E Corporation and not the Utility):

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2015 | | | | |
| (in millions) | Level 1 | Level 2 | Level 3 | Netting [1] | Total |
| **Assets:** | | | | | |
| Money market investments | $ 64 | $ - | $ - | $ - | $ **64** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 36 | - | - | - | **36** |
| Global equity securities | 1,520 | 13 | - | - | **1,533** |
| Fixed-income securities | 694 | 521 | - | - | **1,215** |
| **Total nuclear decommissioning trusts [2]** | **2,250** | **534** | **-** | **-** | **2,784** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | - | 9 | 259 | 18 | **286** |
| Gas | - | 1 | - | 1 | **2** |
| **Total price risk management instruments** | **-** | **10** | **259** | **19** | **288** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 57 | - | - | **57** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **127** | **-** | **-** | **127** |
| Long-term disability trust | | | | | |
| Money market investments | 7 | - | - | - | **7** |
| Global equity securities | - | 26 | - | - | **26** |
| Fixed-income securities | - | 132 | - | - | **132** |
| **Total long-term disability trust** | **7** | **158** | **-** | **-** | **165** |
| **Total assets** | **$ 2,321** | **$ 829** | **$ 259** | **$ 19** | **$ 3,428** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 69 | $ 1 | $ 170 | $ (70) | $ **170** |
| Gas | - | 2 | - | (1) | **1** |
| **Total liabilities** | **$ 69** | **$ 3** | **$ 170** | **$ (71)** | **$ 171** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $ 314 million , primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2014 Level 1 | Level 2 | Level 3 | Netting [(1)] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Money market investments | $ 94 | $ - | $ - | $ - | $ **94** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 17 | - | - | - | **17** |
| Global equity securities | 1,585 | 13 | - | - | **1,598** |
| Fixed-income securities | 741 | 389 | - | - | **1,130** |
| **Total nuclear decommissioning trusts [(2)]** | **2,343** | **402** | **-** | **-** | **2,745** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | - | 17 | 232 | 2 | **251** |
| Gas | 1 | 1 | - | - | **2** |
| **Total price risk management instruments** | **1** | **18** | **232** | **2** | **253** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 42 | - | - | **42** |
| Life insurance contracts | - | 72 | - | - | **72** |
| **Total rabbi trusts** | **-** | **114** | **-** | **-** | **114** |
| Long-term disability trust | | | | | |
| Money market investments | 7 | - | - | - | **7** |
| Global equity securities | - | 25 | - | - | **25** |
| Fixed-income securities | - | 128 | - | - | **128** |
| **Total long-term disability trust** | **7** | **153** | **-** | **-** | **160** |
| **Other investments** | **33** | **-** | **-** | **-** | **33** |
| **Total assets** | **$ 2,478** | **$ 687** | **$ 232** | **$ 2** | **$ 3,399** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 47 | $ 5 | $ 163 | $ (52) | $ **163** |
| Gas | - | 3 | - | - | **3** |
| **Total liabilities** | **$ 47** | **$ 8** | **$ 163** | **$ (52)** | **$ 166** |

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $324 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabi lities shown in the tables above. I nvestments, primarily consisting of equity securities , that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the year ended December 31, 2015 and 2014 .

***Trust Assets***

Nuclear decommissioning trust assets and other trust assets are composed primarily of equity securities and debt securities. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1. Equity securities also include commingled funds that are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world. Investments in these funds are classified as Level 2 because price quotes are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Risk and Audit Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

| (in millions) | Fair Value at At December 31, 2015 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [(1)] |
| Congestion revenue rights | $ 259 | $ 63 | Market approach | CRR auction prices | $ (161.36) - 8.76 |
| Power purchase agreements | $ - | $ 107 | Discounted cash flow | Forward prices | $ 15.08 - 37.27 |

1. Represents price per megawatt-hour

| (in millions) | Fair Value at At December 31, 2014 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [(1)] |
| Congestion revenue rights | $ 232 | $ 63 | Market approach | CRR auction prices | $ (15.97) - 8.17 |
| Power purchase agreements | $ - | $ 100 | Discounted cash flow | Forward prices | $ 16.04 - 56.21 |

(1) Represents price per megawatt-hour

**Level 3 Reconciliation**

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2015 and 2014 , respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| (in millions) | 2015 | 2014 |
| Asset (liability) balance as of January 1 | $ 69 | $ (30) |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [(1)] | 20 | 99 |
| **Asset (liability) balance as of December 31** | **$ 89** | **$ 69** |

(1) The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash , restricted cash , net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreement s approximate their carrying values at December 31, 2015 and 2014 , as they are short-term in nature or have interest rates that reset daily .

- The fair values of the Utility's fixed - rate senior notes and fixed - rate pollution control bond s and PG&E Corporation's fixed - rate senior notes were based on quoted market prices at December 31, 2015 and 2014 .

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2015 | | 2014 | |
| (in millions) | Carrying Amount | Level 2 Fair Value | Carrying Amount | Level 2 Fair Value |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 350 | $ 354 | $ 350 | $ 352 |
| Utility | 14,918 | 16,422 | 13,778 | 15,851 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| **As of December 31, 2015** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 36 | $ - | $ - | $ 36 |
| Global equity securities | 508 | 1,034 | (9) | 1,533 |
| Fixed-income securities | 1,165 | 58 | (8) | 1,215 |
| **Total** [(1)] | **$ 1,709** | **$ 1,092** | **$ (17)** | **$ 2,784** |
| **As of December 31, 2014** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 17 | $ - | $ - | $ 17 |
| Global equity securities | 520 | 1,087 | (9) | 1,598 |
| Fixed-income securities | 1,059 | 75 | (4) | 1,130 |
| Total nuclear decommissioning trusts [(1)] | 1,596 | 1,162 | (13) | 2,745 |
| Other investments | 5 | 28 | - | 33 |
| **Total** | **$ 1,601** | **$ 1,190** | **$ (13)** | **$ 2,778** |

[(1)] Represents amounts before deducting $ 314 million and $324 million at December 31, 2015 and 2014 , respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

| (in millions) | As of December 31, 2015 |
|---|---|
| Less than 1 year | $ 18 |
| 1–5 years | 470 |
| 5–10 years | 273 |
| More than 10 years | 454 |
| **Total maturities of debt securities** | **$ 1,215** |

The following table provides a summary of activity for the debt and equity securities:

| (in millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 1,268 | $ 1,336 | $ 1,619 |
| Gross realized gains on sales of securities held as available-for-sale | 55 | 118 | 94 |
| Gross realized losses on sales of securities held as available-for-sale | (37) | (12) | (13) |

**NOTE 11: EMPLOYEE BENEFIT PLANS**

**Pension Plan and Postretirement Benefits Other than Pensions ("PBOP")**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). T he trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility 's minimum funding requirements related to its pension plans is zero .

PG&E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utility use a fiscal year-end measurement date for all plans.

**Change in Plan Assets, Benefit Obligations , and Funded Status**

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2015 and 2014 :

***Pension Plan***

| **(in millions)** | **2015** | **2014** |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 14,216** | **$ 12,527** |
| Actual return on plan assets | (176) | 1,946 |
| Company contributions | 334 | 332 |
| Benefits and expenses paid | (629) | (589) |
| **Fair value of plan assets at end of year** | **$ 13,745** | **$ 14,216** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 16,696** | **$ 14,077** |
| Service cost for benefits earned | 479 | 383 |
| Interest cost | 673 | 695 |
| Actuarial (gain) loss | (922) | 2,131 |
| Plan amendments | 1 | (1) |
| Transitional costs | 1 | - |
| Benefits and expenses paid | (629) | (589) |
| **Benefit obligation at end of year** [(1)] | **$ 16,299** | **$ 16,696** |
| | | |
| **Funded Status:** | | |
| Current liability | $ (6) | $ (6) |
| Noncurrent liability | (2,547) | (2,474) |
| **Net liability at end of year** | **$ (2,553)** | **$ (2,480)** |

[(1)] PG&E Corporation's accumulated benefit obligation was $ 14.7 billion and $1 4.9 billion at December 31, 2015 and 2014 , respectively.

***Postretirement Benefits Other than Pensions***

| (in millions) | 2015 | 2014 |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 2,092** | **$ 1,892** |
| Actual return on plan assets | (26) | 241 |
| Company contributions | 61 | 57 |
| Plan participant contribution | 68 | 63 |
| Benefits and expenses paid | (160) | (161) |
| **Fair value of plan assets at end of year** | **$ 2,035** | **$ 2,092** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 1,811** | **$ 1,597** |
| Service cost for benefits earned | 55 | 45 |
| Interest cost | 71 | 76 |
| Actuarial (gain) loss | (98) | 166 |
| Transitional costs | 1 | - |
| Benefits and expenses paid | (146) | (140) |
| Federal subsidy on benefits paid | 4 | 4 |
| Plan participant contributions | 68 | 63 |
| **Benefit obligation at end of year** | **$ 1,766** | **$ 1,811** |
| | | |
| **Funded Status:** [1] | | |
| Noncurrent asset | $ 344 | $ 368 |
| Noncurrent liability | (75) | (87) |
| **Net asset at end of year** | **$ 269** | **$ 281** |

[1] At December 31, 2015 and 2014 , the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation ' s Consol idated Statements of Income was as follows:

***Pension Plan***

| (in millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Service cost | $ 479 | $ 383 | $ 468 |
| Interest cost | 673 | 695 | 627 |
| Expected return on plan assets | (873) | (807) | (650) |
| Amortization of prior service cost | 15 | 20 | 20 |
| Amortization of net actuarial loss | 10 | 2 | 111 |
| **Net periodic benefit cost** | **304** | **293** | **576** |
| Less: transfer to regulatory account [1] | 34 | 42 | (238) |
| **Total expense recognized** | **$ 338** | **$ 335** | **$ 338** |

[1] The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

***Postretirement Benefits Other than Pensions***

| (in millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Service cost | $ 55 | $ 45 | $ 53 |
| Interest cost | 71 | 76 | 74 |
| Expected return on plan assets | (112) | (103) | (79) |
| Amortization of prior service cost | 19 | 23 | 23 |
| Amortization of net actuarial loss | 4 | 2 | 6 |
| **Net periodic benefit cost** | **$ 37** | **$ 43** | **$ 77** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record unrecognized prior service costs and unrecognized gains and losses related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax . In addition, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension benefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts that would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

The estimated amounts that will be amortized into net periodic benefit cost s for PG&E Corporation in 2016 are as follows:

| (in millions) | Pension Plan | PBOP Plans |
|---|---|---|
| Unrecognized prior service cost | $ 8 | $ 15 |
| Unrecognized net loss | 24 | 4 |
| **Total** | **$ 32** | **$ 19** |

There were no material differences between the estimated amounts that will be amortized into net period ic benefit costs for PG&E Corporation and the Utility.

**Valuation Assumptions**

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit cost s . The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | December 31, | | | December 31, | | |
| | 2015 | 2014 | 2013 | 2015 | 2014 | 2013 |
| **Discount rate** | 4.37 % | 4.00 % | 4.89 % | 4.27 - 4.48 % | 3.89 - 4.09 % | 4.70 - 5.00 % |
| **Rate of future compensation increases** | 4.00 % | 4.00 % | 4.00 % | - | - | - |
| **Expected return on plan assets** | 6.10 % | 6.20 % | 6.50 % | 3.20 - 6.60 % | 3.30 - 6.70 % | 3.50 - 6.70 % |

The assumed health care cost trend rate as of December 31, 2015 was 7.2 % , decreasing gradually to an ultimate trend rate in 2024 and beyond of approximately 4 % . A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| (in millions) | One-Percentage-Point Increase | One-Percentage-Point Decrease |
|---|---|---|
| Effect on postretirement benefit obligation | $ 113 | $ (114) |
| Effect on service and interest cost | 9 | (9) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate . For the pension plan, the assumed return of 6.1 % compares to a ten-year actual return of 7.8 %. The rate used to discount pension benefits and other benefit s was based on a yield curve developed from market data of over approximately 688 Aa-grade non-callable bonds at December 31, 2015 . This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

**Investment Policies and Strategies**

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funde d status occurs when asset values change differently from liability values and can result in fluctuations in costs in financial reporting , as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended . P G&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts ' asset allocations are meant to manage volatility, reduce costs, and diversify its holdings . Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts' fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility , PG&E Corporation's and the Utility's trust s hold significant allocations in long maturity fixed-income investments . A lthough they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust 's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. R eal assets include commodities futures, REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios .

T arget allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening f uture funded status volatility. Derivative instruments such as equity index futures are used to meet target equity exposure. In addition, derivative instruments such as equity index futures and U.S. treasury futures are used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also used to hedge a portion of the non U.S. dollar exposure of global equity investments .

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Global equity | 25 % | 25 % | 25 % | 32 % | 31 % | 30 % |
| Absolute return | 5 % | 5 % | 5 % | 3 % | 3 % | 3 % |
| Real assets | 10 % | 10 % | 10 % | 7 % | 8 % | 8 % |
| Fixed income | 60 % | 60 % | 60 % | 58 % | 58 % | 59 % |
| **Total** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** |

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

**Fair Value Measurements**

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2015 and 2014 .

| | Fair Value Measurements At December 31, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2015 | | | | 2014 | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Plan:** | | | | | | | | |
| Short-term investments | $ 247 | $ 369 | $ - | **$ 616** | $ 352 | $ 311 | $ - | **$ 663** |
| Global equity | 903 | 2,243 | - | **3,146** | 918 | 2,311 | - | **3,229** |
| Absolute return | - | - | 660 | **660** | - | - | 577 | **577** |
| Real assets | 581 | - | 753 | **1,334** | 620 | - | 675 | **1,295** |
| Fixed-income | 1,841 | 5,516 | 640 | **7,997** | 2,068 | 5,718 | 638 | **8,424** |
| **Total** | **$ 3,572** | **$ 8,128** | **$ 2,053** | **$ 13,753** | **$ 3,958** | **$ 8,340** | **$ 1,890** | **$ 14,188** |
| **PBOP Plans:** | | | | | | | | |
| Short-term investments | $ 20 | $ - | $ - | **$ 20** | $ 28 | $ - | $ - | **$ 28** |
| Global equity | 104 | 545 | - | **649** | 124 | 549 | - | **673** |
| Absolute return | - | - | 65 | **65** | - | - | 55 | **55** |
| Real assets | 69 | - | 77 | **146** | 72 | - | 49 | **121** |
| Fixed-income | 150 | 1,010 | - | **1,160** | 163 | 1,055 | 1 | **1,219** |
| **Total** | **$ 343** | **$ 1,555** | **$ 142** | **$ 2,040** | **$ 387** | **$ 1,604** | **$ 105** | **$ 2,096** |
| **Total plan assets at fair value** | | | | **$ 15,793** | | | | **$ 16,284** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $ 13 million and $24 million at December 31, 2015 and 2014 , respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

***Short-Term Investments***

Short-term investments consist primarily of commingled funds across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

***Global Equity***

The global equity category include s investments in common stock , equity-index futures, and commingled funds comprised of equity securities spread across multiple industries and regions of the world. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active mar kets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets . Commingled equity funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled equity funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled equity funds are categorized as Level 1 and Level 2 assets.

***Absolute Return***

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

***Real Assets***

The real asset category includes portfolios of commodity futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models , and valuation inputs that are unobservable and are considered Level 3 assets.

***Fixed-Income***

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments . Commingled funds are considered Level 2 assets. Corporate fixed-income also includes privately placed debt portfolios which are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and Treasury futures. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

**Transfers Between Levels**

Any transfers between levels in the fair value hierarchy are recognized as of the en d of the reporting period. No material transfers between levels occurred in the years ended December 31, 2015 and 2014 .

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2015 and 2014 :

| | Pension Plan | | | |
|---|---|---|---|---|
| **(in millions)**<br>**For the year ended December 31, 2015** | **Absolute Return** | **Fixed-Income** | **Real Assets** | **Total** |
| Balance at beginning of year | $ 577 | $ 638 | $ 675 | **$ 1,890** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | (7) | 9 | 63 | **65** |
| Relating to assets sold during the period | - | 1 | - | **1** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | 90 | 2 | 17 | **109** |
| Settlements | - | (10) | (2) | **(12)** |
| **Balance at end of year** | **$ 660** | **$ 640** | **$ 753** | **$ 2,053** |

| | Pension Plan | | | |
|---|---|---|---|---|
| **(in millions)**<br>**For the year ended December 31, 2014** | **Absolute Return** | **Fixed-Income** | **Real Assets** | **Total** |
| Balance at beginning of year | $ 554 | $ 625 | $ 544 | **$ 1,723** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 23 | 24 | 54 | **101** |
| Relating to assets sold during the period | - | 4 | - | **4** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | - | 1 | 78 | **79** |
| Settlements | - | (16) | (1) | **(17)** |
| **Balance at end of year** | **$ 577** | **$ 638** | **$ 675** | **$ 1,890** |

| (in millions)<br>For the year ended December 31, 2015 | PBOP Plans<br>Absolute Return | Fixed-Income | Real Assets | Total |
|---|---|---|---|---|
| Balance at beginning of year | $ 55 | $ 1 | $ 49 | **$ 105** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | (1) | - | 5 | **4** |
| Relating to assets sold during the period | - | - | - | **-** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | 11 | - | 23 | **34** |
| Settlements | - | (1) | - | **(1)** |
| **Balance at end of year** | **$ 65** | **$ -** | **$ 77** | **$ 142** |

| (in millions)<br>For the year ended December 31, 2014 | PBOP Plans<br>Absolute Return | Fixed-Income | Real Assets | Total |
|---|---|---|---|---|
| Balance at beginning of year | $ 53 | $ 2 | $ 38 | **$ 93** |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 2 | - | 4 | **6** |
| Relating to assets sold during the period | - | - | - | **-** |
| Purchases, issuances, sales, and settlements: | | | | |
| Purchases | - | - | 7 | **7** |
| Settlements | - | (1) | - | **(1)** |
| **Balance at end of year** | **$ 55** | **$ 1** | **$ 49** | **$ 105** |

There were no material transfers out of Level 3 in 2015 and 2014 .

**Cash Flow Information**

***Employer Contributions***

PG&E Corporation and the Utility contributed $ 334 million to the pension benefit plans and $ 61 million to the other benefit plans in 2015 . These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2015 . The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $ 327 million and $ 61 million to the pension plan and other postretirement benefit plans, respectively, for 2016 .

***Benefits Payments and Receipts***

As of December 31, 2015 , the estimated benefits expected to be paid and the estimated federal subsidies expected to be receive d in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

| (in millions) | Pension Plan | PBOP Plans | Federal Subsidy |
|---|---|---|---|
| 2016 | $ 695 | $ 89 | $ (6) |
| 2017 | 739 | 95 | (7) |
| 2018 | 780 | 101 | (7) |
| 2019 | 818 | 107 | (8) |
| 2020 | 854 | 113 | (8) |
| Thereafter in the succeeding five years | 4,728 | 593 | (17) |

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

**Retirement Savings Plan**

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees t o make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were $ 89 million, $80 million, and $71 million in 2015 , 2014 , and 2013 , respectively.

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

## NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility ' s significant related party transactions were :

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2015** | **2014** | **2013** |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 6 | $ 5 | $ |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 53 | $ 54 | $ |
| Utility employee benefit due to PG&E Corporation | 82 | 70 | |

At December 31, 2015 and 2014 , the Utility had receivable s of $ 22 million and $ 17 m illion, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payable s of $ 21 million and $20 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

**NOTE 13: CONTINGENCIES AND COMMITMENTS**

PG &E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation . The U tility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below.

**Enforcement and Litigation Matters**

***CPUC Matters***

*Order Instituting an Investigation into Com pliance with Ex P arte Communication Rules*

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have been made or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker or a Commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in the CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices. A prehearing conference in the OII has been scheduled for March 1, 2016.

The CPUC will determine any penalties that might be imposed on the Utility and determine whether shareholders or ratepayers will bear the costs of the investigation. The CPUC can impose fines up to $50,000 for each violation, per day. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this discretion in determining penalties.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII but they are unable to reasonably estimate the amount or range of future charges that could be incurred , because i t is uncertain how the CPUC will calculate the number of violations or the penalty for any violations, and whether the CPUC will consider additional communications in the OII, including those identified in a motion filed on December 1, 2015, by the City of San Bruno in the 2015 GT&S rate case . It is also uncertain whether the CPUC will take additional action in any of the proceedings in which the Utility has self-reported communications that may have violated the CPUC's ex parte rules .

Finally, t he U.S. Attorney's Office in San Francisco and the California Attorney General's office also have been inv estigating matters related to allegedly improper communications between the Utility and CPUC personnel . The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility .

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices with respect to maintaining safe operation of its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014, for which the CPUC has previously imposed a penalty of $10.85 million.

On September 30, 2015, the SED submitted its supplemental testimony, which included incidents allegedly related to record-keeping that had not been identified in the initial order, and also asserted violations related to the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities. Evidentiary hearings were held during January 2016. Opening briefs are due by February 26, 2016 and reply briefs are due by March 31, 2016. The SED has indicated it will seek significant penalties, the amount of which is expected to be disclosed in its brief.

P G&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the form of fines or other remedies, including possible future unrecoverable costs to implement operational remedies. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion (discussed above) .

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

*Potential Safety Citations*

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. In addition, the California utilities are required to inform the SED of self-identified or self-corrected violations. The CPUC has delegated authority to the SED to issue citations and impose fines for violations identified through audits, investigations, or self-reports. T he SED can consider the discretionary factors discussed above (see " Order Instituting an Investigation into Compliance with Ex parte Communication Rules " above) in determining the number of violations and whether to impose daily fines for continuing violations. The SED is required, however, to impose the maximum statutory penalty of $50,000 for each separate violation .

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The Utility believes it is probable that the SED will impose fines or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

***Federal Matters***

*Federal Criminal Indictment*

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that superseded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. On December 23, 2015, the court presiding over the federal criminal pro ceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. The maximum statutory fine for each felony count is $500,000, for total potential fines of $6.5 million. On December 8, 2015, the court also issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act . The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of gross gains prior to deciding whether to dismiss those allegations. (Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million.) After considering the additional information submitted by the government, on February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after th e trial on the criminal charges. The trial on the criminal charges currently is scheduled to begin March 22 , 2016.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Consolidated Financial Statements as such amounts are not considered to be probable.

*Other Federal Matters*

The Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. It is uncertain whether any additional charges will be brought against the Utility.

**Capital Expenditures R elating to Pipeline Safety Enhancement Pla n**

A t December 31, 2015 , approximately $ 664 m illion of PSEP-related capital costs is recorded in property, plant, and equipment on the Consolidated Balance Sheets. The Utility would be required to record charges to the statement of income in future periods to the extent total forecasted PSEP-related capital costs are higher than currently expected.

**Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission**

On Ap ril 9, 2015, the CPUC approved final decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record - keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record - keeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion c omprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. In August 2015, the Utility paid the $300 million fine. At December 31, 2015, the Consolidated Balance Sheets include $400 million in current regulatory liabilities for the one-time bill credit that will be provided to the Utility's natural gas customers in 2016. On January 14, 2016, the CPUC issued final decisions to close these investigative proceedings.

The Penalty Decision requires that at least $689 million of the $850 million disallowance be allocated to capital expenditures, and that the Utility be precluded from including these capital costs in rate base. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the 2015 GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent. The CPUC is expected to issue a final decision in the Utility's 2015 GT&S rate case in 2016 to identify safety-related projects and programs that will be subject to the disallowance. It is uncertain how much of the Utility's costs to perform the safety-related projects and programs the CPUC will identify as counting toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. As a result, the total shareholder-funded obligation could exceed $850 million.

For the year ended December 31, 2015, the Utility recorded additional charges in operating and maintenance expenses in the Consolidated Statements of Income of $907 million as a result of the Penalty Decision. The cumulative charges at December 31, 2015, and the additional future charges to reach the $1.6 billion total are shown in the following table:

| (in millions) | Year Ended December 31, 2015 | Cumulative Charges December 31, 2015 | Future Charges and Costs | Total Amount |
|---|---|---|---|---|
| Fine payable to the state [(1)] | $ 100 | $ 300 | $ - | $ 300 |
| Customer bill credit | 400 | 400 | - | 400 |
| Charge for disallowed capital [(2)] | 407 | 407 | 282 | 689 |
| Disallowed revenue for pipeline safety expenses [(3)] | - | - | 161 | 161 |
| CPUC estimated cost of other remedies [(4)] | - | - | - | 50 |
| **Total Penalty Decision fines and remedies** | **$ 907** | **$ 1,107** | **$ 473** | **$ 1,600** |

(1) In March 2015, the Utility increased its accrual from $200 million at December 31, 2014 to $300 million.
(2) The Penalty Decision prohibits the Utility from recovering certain expenses and capital spending associated with pipeline safety-related projects and prog rams that the CPUC will identify in the final decision to be issued in the Utility's 2015 GT&S rate c ase. The Utility estimates that approximately $407 mi llion of capital spending (which include less than $1 million for remedy related capital costs) in the year ended December 31, 2015 is probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.
(3) These costs are being expensed as incurred. Future GT&S revenues will be reduced for these unrecovered expenses.
(4) In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision and does not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. These costs are being expensed as incurred .

**Other Legal and Regulatory Contingencies**

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies a re reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred.

***Investigation of the Butte Fire***

In September 2015, a wildfire (known as the "Butte f ire") ignited and spread in Amador and Calaveras Counties in Northern California. The California Department of Forestry and Fire Protection ("Cal Fire") is i nvestigating the source of the Butte F ire to determine whether a tree contacted a power line operated by the Utility and was the cause of the fire. Cal Fire has reported that as a result of the fire there were two deaths and 965 structures, including 571 houses, were damaged or destroyed. Cal Fire's investigation is expected to conclude in 2016.

Approximately 27 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving more than 600 individual plaintiffs and their insurance companies. Plaintiffs and the Utility filed petitions with the California Judicial Council to coordinate these cases. The petitions were assigned to the Calaveras Superior Court for a recommendation to the Judicial Council. On January 21, 2016, the Calaveras Superior Court issued an order recommending to the Judicial Council that the cases be coordinated in the Superior Court of California, Sacramento County, for all purposes including trial. Among other factors, the Court found that coordination requires a court with a significant number of judges and complex litigation support personnel, neither of which are present in Calaveras County.

It is estimated that losses related to structures, contents, other personal property, and fire suppression costs associated with the Butte fire, will range from $350 million to $450 million. This range is based on estimates about the number, size, and type of structures damaged or destroyed, assumptions about the contents of such structures and other personal property damage, and information about the amount of fire suppression costs asso ciated with prior similar fires. Th e Utility believes that it is reasonably possible that it would be liable for some or all of these and other costs, such as costs associated with tree damage, personal injury, business interruption losses, and other damages. The Utility is unable to reasonably estimate these other costs at this time due to the limited information available.

The Utility has insurance coverage for these types of claims. If the amount of insurance is insufficient to cover the Utility's liability resulting from the Butte fire, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected.

***Rehearing of CPUC Decisions Approving Energy Efficiency Incentive Awards***

On September 17, 2015, the CPUC issued an order granting TURN's and the ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California investor-owned utilities for the 2006-2008 energy efficiency program cycle. Under the ratemaking mechanism applicable to the 2006-2008 program cycle, the maximum amount of incentives that the Utility could have earned (or the maximum amount that the Utility could have been required to reimburse customers) over the 2006-2008 program cycle was $180 million. The Utility was awarded a total of $104 million for the 2006-2008 program cycle. In the re-opened energy efficiency proceeding, the CPUC will evaluate whether incentives awarded to the California investor-owned utilities were just and reasonable, and whether any refunds are due. The parties are required to submit proposals to resolve the issues in the proceeding by March 18 , 2016. Comments on the proposals are due on April 8 , 2016 and evidentiary hearings, if needed, would be held in July 2016. It is uncertain when the CPUC will issue a decision and whether the Utility will be required to refund amounts or incur other obligations related to the 2006-2008 program cycle. PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations.

***Other Contingencies***

Accruals for other legal and regulatory contingencies (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters" and "Other Legal and Regulatory Contingencies" ) totaled $ 63 million at December 31 , 2015, and $55 million at December 31, 2014. These amounts are included in other current liabilities in the Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Environm ental Remediation Contingencies**

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **December 31, 2015** | **December 31, 2014** |
| Topock natural gas compressor station [1] | $ 300 | $ 291 |
| Hinkley natural gas compressor station [1] | 140 | 158 |
| Former manufactured gas plant sites owned by the Utility or third parties | 271 | 257 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites | 164 | 150 |
| Fossil fuel-fired generation facilities and sites | 94 | 98 |
| **Total environmental remediation liability** | **$ 969** | **$ 954** |

[1] See "Natural Gas Compressor Station Sites" below.

At December 31, 2015 the Utility expected to recover $ 695 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. T he Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the co sts associated with the Hinkley site.

***Natural Gas Compressor Station Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as the "Topock site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

*Hinkley Site*

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. O n November 4, 201 5 , the Regional Board adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the po tential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts; define the boundaries of the chromium plume, and take other action. Additionally, the final order requires set ting plume capture requirements, requires establish ing a monitoring and reporting program , and finalizes deadlines for the Utility to meet interim cleanup targets. The clean-up and abatement order did not have a material impact on the Utility's consolidated financial statements.

The Utility's environmental remediation liability at December 31, 201 5 reflects the Utility's best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the f inal remediation plan and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

*Topock Site*

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California D epartment of T oxic S ubstances C ontrol and the U.S. Department of the Inter ior. I n November 201 5 , the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The DTSC is conducting an additional environmental review of the proposed design , and the Utility anticipates that the DTSC's draft environmental impact report will be issued for public comment in July 2016. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in December 2016. After the Utility modifies its design in response to the final report, the Utility plans to seek approval to begin construction of the new in-situ treatment system in early 2017.

The Utility's environmental remediation liability at December 31, 2015 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

***Reasonably Possible Environmental Contingencies***

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $ 1.9 billion (including amounts related to the Hinkley and Topock sites described above ) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially ab le to contribute to these costs . The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations during the period in which they are recorded.

**Nuclear Insurance**

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $ 3.5 billion per nuclear incident and $ 2.8 billion per non-nuclear incident for Diablo Canyon . Humboldt Bay Unit 3 has up to $ 131 million of coverage for nuclear and non-nuclear property damages. If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31 , 201 5 , the current maximum aggregate annual retrospective premium obligation for the Utility is approximately $ 60 million.

NEIL also provide s coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3. 5 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3. 5 billion policy limit amount.

Under the Price-Anderson Act, public liability claims that arise from nuclear incid ents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $13. 5 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $13. 5 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a m aximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018 .

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $ 375 million per incident. In addition, the Utility has $ 53 million of liability insurance for Humboldt Bay Unit 3 and has a $ 500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the lia bility insurance.

**Resolution of Remaining Chapter 11 Disputed Claims**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the California Power Exchange wholesale electricity markets during this period .

At December 31, 2015 , and December 31, 2014 , the Consolidated Balance Sheets reflected $ 454 million and $434 million, respectively, in net Disputed claims and customer refunds, including both principal and interest. At December 31, 2015 and 2014 , the Utility held $ 228 million and $291 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

Interest accrues on the remaining net disputed claims liability at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates , these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims liability , the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims liability and when such interest is paid.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has entered into a number of settlement agreement s with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, a mounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FER C. Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

In July 2014, a settlement agreement between the Utility and an electric supplier became effective, resolving a portion of the Utility's net disputed claims and resulting in refunds to customers of $ 312 million. No significant settlement agreements were reached in 2015. The Utility is uncertain when and how the remaining net disputed claims liability will be resolved.

**Purchase Commitments**

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2015 :

| | Power Purchase Agreements | | | | | |
|---|---|---|---|---|---|---|
| (in millions) | Renewable Energy | Conventional Energy | Other | Natural Gas | Nuclear Fuel | Total |
| 2016 | $ 2,177 | $ 772 | $ 504 | $ 421 | $ 113 | $ 3,987 |
| 2017 | 2,201 | 787 | 380 | 150 | 100 | 3,618 |
| 2018 | 2,075 | 706 | 359 | 105 | 96 | 3,341 |
| 2019 | 2,087 | 694 | 290 | 105 | 98 | 3,274 |
| 2020 | 2,077 | 674 | 213 | 103 | 133 | 3,200 |
| Thereafter | 29,098 | 1,729 | 997 | 543 | 185 | 32,552 |
| **Total purchase commitments** | **$ 39,715** | **$ 5,362** | **$ 2,743** | **$ 1,427** | **$ 725** | **$ 49,972** |

***Third-Party Power Purchase Agreements***

In the ordinary course of business, the Utility enters into various agreements , including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity . The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or el ectricity at the date of delivery.

*Renewable Energy Power Purchase Agreement s .* In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement . The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow significantly. As of December 31, 2015, renewable energy contracts expire at various dates between 2016 and 2043 .

*Conventional Energy Power Purchase Agreements .* T he Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements . The Utility's obligation under a portion of these agreements is contingent on the third part ies ' development of new generation facilit ies to provide capacity and energy products to the Utility . As of December 31, 2015, these power purchase agreements expire at various dates between 2016 and 2033 .

*Other Power Purchase Agreements.* The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Several of these agreements are treated as capital leases. At December 31, 2015 and 2014 , net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $ 54 million and $74 million including accumulated amortization of $ 147 million and $ 128 millio n, respectively. The present value of the future minimum lease payments due under these agreements included $ 19 million and $20 million in Current Liabilities and $ 35 million and $54 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2015 , QF contracts in operation expire at various dates between 2016 and 2028 . In addition, t he Utility has agreements with various irrigation districts and water agenci es to purchase hydroelectric power.

The costs incurred for all power purchase s and electric capacity amounted to $ 3.5 billion in 2015, $3.6 billion in 2014, and $3.0 billion in 2013.

***Natural Gas Supply, Transportation, and Storage Commitments***

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities . The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada , the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2016 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

Costs incurred for natural gas purchases, natural gas transportation services, and natural ga s storage, which include contracts with terms of less than 1 year, amounted to $ 0.9 billion in 2015 , $1.4 billion in 2014 , and $1.6 billion in 2013 .

***Nuclear Fuel Agreements***

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2016 and 2025 and are intended to ensure long-term nuclear fuel supply. T he Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to $128 milli on in 2015 , $105 million in 2014 , and $162 million in 2013 .

**O ther Commitments**

PG&E Corporation and t he Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2016 and 2052 . At December 31, 2015 , the future minimum payments related to these commitments were as follows:

| (in millions) | Operating Leases |
|---|---|
| 2016 | $ 40 |
| 2017 | 41 |
| 2018 | 40 |
| 2019 | 38 |
| 2020 | 37 |
| Thereafter | 194 |
| **Total minimum lease payments** | **$ 390** |

Payments for other commitments related to operating leases amounted to $ 41 million in 2015 , $ 42 million in 2014 , and $ 40 million in 2013 . Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

**QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)**

| | Quarter ended | | | |
|---|---|---|---|---|
| (in millions, except per share amounts) | December 31 | September 30 | June 30 | March 31 |
| **2015** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 4,167 | $ 4,550 | $ 4,217 | $ 3,899 |
| Operating income | 205 | 545 | 687 | 71 |
| Income tax (benefit) provision [(1)] | (111) | 67 | 110 | (93) |
| Net income [(2)] | 138 | 310 | 406 | 34 |
| Income available for common shareholders | 134 | 307 | 402 | 31 |
| Comprehensive income | 137 | 310 | 406 | 17 |
| Net earnings per common share, basic | 0.27 | 0.63 | 0.84 | 0.06 |
| Net earnings per common share, diluted | 0.27 | 0.63 | 0.83 | 0.06 |
| Common stock price per share: | | | | |
| High | 54.50 | 54.41 | 54.27 | 60.15 |
| Low | 51.65 | 47.60 | 49.10 | 51.38 |
| **UTILITY** | | | | |
| Operating revenues | $ 4,167 | $ 4,550 | $ 4,216 | $ 3,900 |
| Operating income | 208 | 544 | 687 | 72 |
| Income tax (benefit) provision [(1)] | (114) | 72 | 115 | (92) |
| Net income [(2)] | 147 | 305 | 406 | 4 |
| Income available for common stock | 143 | 302 | 402 | 1 |
| Comprehensive income | 145 | 305 | 406 | 4 |
| | | | | |
| **2014** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues [(3)] | $ 4,308 | $ 4,939 | $ 3,952 | $ 3,891 |
| Operating income | 383 | 1,065 | 518 | 484 |
| Income tax provision | 35 | 115 | 104 | 91 |
| Net income [(4)] | 135 | 814 | 271 | 230 |
| Income available for common shareholders | 131 | 811 | 267 | 227 |
| Comprehensive income | 120 | 796 | 260 | 235 |
| Net earnings per common share, basic | 0.28 | 1.72 | 0.57 | 0.49 |
| Net earnings per common share, diluted | 0.27 | 1.71 | 0.57 | 0.49 |
| Common stock price per share: | | | | |
| High | 54.98 | 48.07 | 48.23 | 44.73 |
| Low | 44.38 | 43.00 | 42.37 | 39.60 |
| **UTILITY** | | | | |
| Operating revenues [(3)] | $ 4,308 | $ 4,939 | $ 3,951 | $ 3,890 |
| Operating income | 383 | 1,059 | 525 | 485 |
| Income tax provision | 59 | 115 | 110 | 100 |
| Net income [(4)] | 162 | 793 | 250 | 228 |
| Income available for common stock | 158 | 790 | 246 | 225 |
| Comprehensive income | 154 | 793 | 250 | 228 |

[(1)] In the first quarter of 2015, the Utility had an income tax benefit, primarily due to the impact of the Penalty Decision . ( See note (2) below. ) In the fourth quarter of 2015, the Utility had an income tax benefit, primarily due to lower income before taxes and an audit settlement received.

[2] In the first quarter of 2015 , the Utility recorded total charges of $553 million related to the Penalty Decision, including $53 million in estimated capital spending that is probable of disallowance. In the second, third, and fourth quarters of 2015, the Utility recorded $75 million, $142 million, and $137 million, respectively, in estimated capital spending that is probable of disallowance. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

[3] In the third quarter of 2014, the Utility recorded an increase to base revenues as authorized by the CPUC in the 2014 GRC decision.

[4] The Utility recorded charge s to net income of $116 million in the fourth quarter of 2014 for PSEP capital costs that are forecasted to exceed the authorized amounts . (See Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.)

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of PG&E Corporation and Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2015 .

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2015 , based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the internal control over financial reporting of PG&E Cor poration and subsidiaries (the " Company " ) and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2015 , based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company ' s and the Utility ' s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management ' s Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company ' s and the Utility ' s internal control over financial reporting based on our audits.

We conducted our audit s in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit s to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit s included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company ' s internal control over financial reporting is a process designed by, or under the supervision of, the company ' s principal executive and principal financial officers, or persons performing similar functions, and effected by the company ' s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company ' s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company ' s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2015 of the Company and the Utility and our report dated February 18, 2016 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 18 , 2016

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the accompanying consolidated balance sheets of PG&E Cor poration and subsidiaries (the " Company " ) and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2015 and 2014 , and the Company ' s related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility ' s related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 . These financial statements are the responsibility of the Company ' s and the Utility ' s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2015 and 2014 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 , in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company ' s and the Utility's internal control over financial reporting as of December 31, 2015 , based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18 , 2016 expressed an unqualified opinion on the Company ' s and the Utility ' s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 18, 2016

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

## ITEM 9A. CONTROLS AND PROCEDURES

**Evaluation of Disclosure Controls and Procedures**

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2015 , PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

**Management's Annual Report on Internal Control over Financial Reporting**

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

**Registered Public Accounting Firm's Report on Internal Control over Financial Reporting**

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2015 , based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**Changes in Internal Control Over Financial Reporting**

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

## ITE M 9B. OTHER INFORMATION

Not applicable.

# PART III

## ITEM 10 . DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this report. Other information regarding directors is set forth under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 201 6 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act is included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 201 6 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on PG&E Corporation ' s website *www.pgecorp.com* , and the Utility ' s website, *www.pge.com* : (1) the codes of conduct and ethics adopted by PG&E Corporation and the Utility applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation ' s and the Utility ' s corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies ' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and the Utility that apply to their respective Chief Executive Officers, Chief Financial Officers, or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within four business days of the waiver.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

During 2015 , there were no material changes to the procedures described in PG&E Corporation ' s and the Utility ' s Joint Proxy Statement relating to the 2015 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation ' s or Pacific Gas and Electric Company ' s Boards of Directors.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial expert" as defined by the SEC is set forth under the headings "Corporate Governance – Board Committee Duties – Audit Committees" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 201 6 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 11 . EXECUTIVE COMPENSATION**

Information responding to Item 11, for each of PG&E Corporation and the Utility, is set forth under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2015 ," "Grants of Plan-Based Awards in 2015 ," "Outstanding Equity Awards at Fiscal Year End - 2015 ," "Option Exercises and Stock Vested During 2015 ," "Pension Benefits – 2015 ," "Non-Qualified Deferred Compensation – 2015 ," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2015 Director Compensation" in the Joint Proxy Statement relating to the 2016 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth un der th e headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2016 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Equity Compensation Plan Information***

The following table provides information as of December 31, 2015 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|---|---|---|---|
| Equity compensation plans approved by shareholders | 6,027,349 (1) | $ 35.53 (2) | 15,674,803 (3) |
| Equity compensation plans not approved by shareholders | - | - | - |
| Total equity compensation plans | 6,027,349 (1) | $ 35.53 (2) | 15,674,803 (3) |

(1) Includes 30,020 phantom stock units, 2,335,148 restricted stock units and 3,658,091 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares granted in 2013, reflects the actual payout percentage of 50%. The actual number of shares issued can range from 0% to 200% of target depending on achievement of performance objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) This is the weighted average exercise price for the 4,090 options outstanding as of December 31, 2015.

(3) Represents the total number of shares available for issuance under all of PG&E Corporation's equity compensation plans as of December 31, 2015. Stock-based awards granted under these plans include restricted stock units, performance shares and phantom stock units. The 2014 LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the 2014 LTIP, less approximately 2.7 million shares for awards granted under the 2006 LTIP from January 1, 2014 through May 11, 2014. In addition, if any awards outstanding under the 2006 LTIP at December 31, 2013 are cancelled, forfeited or expire without being settled in full, shares of stock allocable to the terminated portion of such awards shall again be available for issuance under the 2014 LTIP.

F or more information, see Note 5 of the Notes to the Consolidate d Financial Statements in Item 8.

## ITE M 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information responding to Item 13, for each of PG&E Corporation and the Utility, is included under the headings "Related Party Transactions" and "Corporate Governance – Board and Director Independence and Qualifications" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2016 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 14 . PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to Item 14, for each of PG&E Corporation and the Utility, is set forth under the heading "Information Regarding the Independent Registered Public Accounting Firm for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2016 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

**A. The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as p art of this report in Item 8 :

Consolidated Statements of Income for the Years Ended December 31, 201 5 , 201 4, and 2013 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 201 5 , 201 4, and 2013 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Bal ance Sheets at December 31, 2015 and 201 4 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 201 5 , 201 4, and 2013 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 201 5 , 201 4, and 2013 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 201 5 , 201 4, and 2013 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Management's Report on Internal Controls

Reports of Independent Registered Public Accountin g Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Report of Independent Registered Public Accountin g Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2015 and 201 4 and for the Years Ended December 31, 201 5 , 201 4, and 2013 .

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 201 5 , 201 4, and 2013 .

3. Exhibits required by Item 601 of Regulation S-K

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of February 19, 2014 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of August 17, 2015 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K filed on July 14, 2015 (File No. 1-2348), Exhibit 99.2) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility’s issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |

| | |
|---|---|
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No.1 2348), Exhibit 4.1) |
| 4.20 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1 - 2348), Exhibit 4.1) |

| | |
|---|---|
| 4.2 1 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1 - 2348), Exhibit 4.1) |
| 4.22 | Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on June 12, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.23 | Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on November 5, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.24 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.25 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |
| 10.1 | Second Amended and R estated C redit A greement dated as of April 27, 2015, among (1) PG&E Corporation , as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC , as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association , as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank , National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Second Amended and R estated C redit A greement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company , as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC , as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. , as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association , as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.4 | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |

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| 10.5 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.6 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.7 ) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4 ) |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.11 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.8 ) |
| 10.12 | * | Performance Share Agreement subject to safety and custom er affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.9 ) |
| 10.13 | * | Performance Share Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5 ) |
| 10.14 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.15 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.16 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.17 | * | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.18 | * | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.19 | * | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.4) |
| 10.20 | * | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.5) |

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| 10.21 | * | Non-Annual Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.6) |
| 10.22 | * | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.7) |
| 10.23 | * | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.8) |
| 10.24 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |
| 10.25 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.26 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.27 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick olas Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.28 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Steven Malnight dated February 22, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-2348), Exhibit 10.3 ) |
| 10.29 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.30 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.31 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.32 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.33 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.34 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.35 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |

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| 10.36 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.37 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.38 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers |
| 10.39 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6 , 2015 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2014) (File No. 1-12609), Exhibit 10. 37 ) |
| 10.40 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.41 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.42 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2016 |
| 10.43 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.44 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.45 | * | Form of Restricted Stock Unit Agreement for 2015 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.46 | * | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 4 ) |
| 10.47 | * | Form of Restrict ed Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Ex hibit 10.2 ) |
| 10.48 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.49 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.50 | * | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.51 | * | Form of Restricted Stock Unit Agreement for 2014 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan ( incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.52 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |

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| 10.53 | * | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 5 ) |
| 10.54 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 6 ) |
| 10.55 | * | Form of Perf ormance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3 ) |
| 10.56 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |
| 10.57 | * | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.58 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.59 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.60 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.61 | * | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.62 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.63 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.64 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.65 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10. 2 ) |
| 10.66 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.67 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.68 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |

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|---|---|---|
| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23 | | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |

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| * | Management contract or compensatory agreement. |
| ** | Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report. |

## SIGNATURES

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2015 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| PG&E CORPORATION (Registrant) | | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) | |
|---|---|---|---|
| | ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | | NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos |
| By: | Chairman of the Board, Chief Executive Officer, and President | By: | President, Gas |
| Date: | February 18, 2016 | Date: | February 18, 2016 |
| | | | GEISHA J. WILLIAMS<br>Geisha J. Williams |
| | | By: | President, Electric |
| | | Date: | February 18, 2016 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| **A. Principal Executive Officers** | | |
| ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation) | February 18, 2016 |
| NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | President, Gas (Pacific Gas and Electric Company) | February 18, 2016 |
| GEISHA J. WILLIAMS<br>Geisha J. Williams | President, Electric (Pacific Gas and Electric Company) | February 18, 2016 |
| **B. Principal Financial Officers** | | |
| JASON P. WELLS<br>Jason P. Wells | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 18, 2016 |
| DINYAR B. MISTRY<br>Dinyar B. Mistry | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 18, 2016 |

**C. Principal Accounting Officer**

| | | |
|---|---|---|
| DINYAR B. MISTRY<br>Dinyar B. Mistry | Vice President and Controller (PG&E Corporation)<br>Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 18, 2016 |

**D. Directors**

| | | |
|---|---|---|
| * LEWIS CHEW<br>Lewis Chew | Director | February 18, 2016 |
| * ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Director | February 18, 2016 |
| * FRED J. FOWLER<br>Fred J. Fowler | Director | February 18, 2016 |
| * MARYELLEN C. HERRINGER<br>Maryellen C. Herringer | Director | February 18, 2016 |
| * RICHARD C. KELLY<br>Richard C. Kelly | Director | February 18, 2016 |
| * ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 18, 2016 |
| * RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 18, 2016 |
| * FORREST E. MILLER<br>Forrest E. Miller | Director | February 18, 2016 |
| * ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 18, 2016 |
| * BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 18, 2016 |
| * ANNE SHEN SMITH<br>Anne Shen Smith | Director | February 18, 2016 |
| * NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | Director (Pacific Gas and Electric Company only) | February 18, 2016 |
| * GEISHA J. WILLIAMS<br>Geisha J. Williams | Director (Pacific Gas and Electric Company only) | February 18, 2016 |
| * BARRY LAWSON WILLIAMS<br>Barry Lawson Williams | Director | February 18, 2016 |

*By: HYUN PARK
HYUN PARK, Attorney-in-Fact

**REPO RT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "U tility") as of December 31, 2015 and 201 4 , and for each of the three years in the period ended December 31, 201 5 , and the Company's and the Utility's internal control over financial reporting as of December 31, 201 5 , and have issued our reports thereon dated February 1 8 , 201 6; such reports are included in this Form 10-K . Our audits also included the consolidated financial statement schedules of the Company and the Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 1 8 , 201 6

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2015** | **2014** | **2013** |
| Administrative service revenue | $ 51 | $ 51 | $ 41 |
| Operating expenses | (53) | (53) | (42) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (10) | (14) | (25) |
| Other income (expense) | 30 | (1) | (57) |
| Equity in earnings of subsidiaries | 852 | 1,413 | 848 |
| Income before income taxes | 871 | 1,397 | 766 |
| Income tax benefit | 3 | 39 | 48 |
| **Net income** | **$ 874** | **$ 1,436** | **$ 814** |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $10, and $80, at respective dates) | $ (1) | $ (14) | $ 113 |
| Net change in investments (net of taxes of $12, $17, and $26, at respective dates) | (17) | (25) | 38 |
| Total other comprehensive income (loss) | (18) | (39) | 151 |
| **Comprehensive Income** | **$ 856** | **$ 1,397** | **$ 965** |
| **Weighted Average Common Shares Outstanding, Basic** | **484** | **468** | **444** |
| **Weighted Average Common Shares Outstanding, Diluted** | **487** | **470** | **445** |
| **Net earnings per common share, basic** | **$ 1.81** | **$ 3.07** | **$ 1.83** |
| **Net earnings per common share, diluted** | **$ 1.79** | **$ 3.06** | **$ 1.83** |

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED BALANCE SHEETS**

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2015** | **2014** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 64 | $ 96 |
| Advances to affiliates | 22 | 31 |
| Income taxes receivable | 24 | 29 |
| Other | 1 | 38 |
| **Total current assets** | **111** | **194** |
| **Noncurrent Assets** | | |
| Equipment | 2 | 2 |
| Accumulated depreciation | (2) | (1) |
| **Net equipment** | **-** | **1** |
| Investments in subsidiaries | 16,837 | 16,003 |
| Other investments | 130 | 117 |
| Deferred income taxes | 250 | 260 |
| **Total noncurrent assets** | **17,217** | **16,381** |
| **Total Assets** | **$ 17,328** | **$ 16,575** |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Accounts payable – other | 3 | 67 |
| Other | 246 | 269 |
| **Total current liabilities** | **249** | **336** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 350 | 350 |
| Other | 153 | 141 |
| **Total noncurrent liabilities** | **503** | **491** |
| **Common Shareholders' Equity** | | |
| Common stock | 11,282 | 10,421 |
| Reinvested earnings | 5,301 | 5,316 |
| Accumulated other comprehensive income (loss) | (7) | 11 |
| **Total common shareholders' equity** | **16,576** | **15,748** |
| **Total Liabilities and Shareholders' Equity** | **$ 17,328** | **$ 16,575** |

**PG&E CORPORATION**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **Cash Flows from Operating Activities:** | | | |
| Net income | $ 874 | $ 1,436 | $ 814 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 66 | 65 | 54 |
| Equity in earnings of subsidiaries | (852) | (1,413) | (848) |
| Deferred income taxes and tax credits-net | 10 | (72) | (10) |
| Noncurrent income taxes receivable/payable | - | 5 | - |
| Current income taxes receivable/payable | 5 | (16) | 20 |
| Other | (70) | 43 | (20) |
| **Net cash provided by operating activities** | **33** | **48** | **10** |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (705) | (978) | (1,371) |
| Dividends received from subsidiaries [1] | 716 | 716 | 716 |
| Proceeds from tax equity investments | - | 368 | 275 |
| Other | - | - | (8) |
| **Net cash provided by (used in) investing activities** | **11** | **106** | **(388)** |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings (repayments) under revolving credit facilities | - | (260) | 140 |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $3 million | - | 347 | - |
| Repayments of long-term debt | - | (350) | - |
| Common stock issued | 780 | 802 | 1,045 |
| Common stock dividends paid [2] | (856) | (828) | (782) |
| Other | - | - | (1) |
| **Net cash provided by (used in) financing activities** | **(76)** | **(289)** | **402** |
| **Net change in cash and cash equivalents** | **(32)** | **(135)** | **24** |
| **Cash and cash equivalents at January 1** | **96** | **231** | **207** |
| **Cash and cash equivalents at December 31** | **$ 64** | **$ 96** | **$ 231** |
| | | | |
| **Supplemental disclosure of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (9) | $ (15) | $ (23) |
| Income taxes, net | - | 1 | 21 |
| **Supplemental disclosure of noncash investing and financing activities** | | | |
| Noncash common stock issuances | $ 21 | $ 21 | $ 22 |
| Common stock dividends declared but not yet paid | 224 | 217 | 208 |

[1] Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries an investing cash flow.
[2] In January, April, July, and October of 2015, 2014, and 2013, respectively, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

**PG&E Corporation**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 201 5, 2014 , and 201 3**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions [2] | Balance at End of Period |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |
| 2014: | | | | | |
| Allowance for uncollectible accounts [1] | $ 80 | $ 41 | $ - | $ 55 | $ 66 |
| 2013: | | | | | |
| Allowance for uncollectible accounts [1] | $ 87 | $ 53 | $ - | $ 60 | $ 80 |

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**Pacific Gas and Electric Company**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 201 5 , 201 4 , and 201 3**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions [2] | Balance at End of Period |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |
| 2014: | | | | | |
| Allowance for uncollectible accounts [1] | $ 80 | $ 41 | $ - | $ 55 | $ 66 |
| 2013: | | | | | |
| Allowance for uncollectible accounts [1] | $ 87 | $ 53 | $ - | $ 60 | $ 80 |

[1] Allowance for uncollectible accounts is deducted from “Accounts receivable - Customers.”
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off .

**EXHIBIT INDEX**

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of February 19, 2014 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of August 17, 2015 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K filed on July 14, 2015 (File No. 1-2348), Exhibit 99.2) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility’s issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |

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|---|---|
| 4.9 | Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No.1 2348), Exhibit 4.1) |

| | |
|---|---|
| 4.20 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated August 18, 2014 (File No. 1 - 2348), Exhibit 4.1) |
| 4.2 1 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 6, 2014 (File No. 1 - 2348), Exhibit 4.1) |
| 4.22 | Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K filed on June 12, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.23 | Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K filed on November 5, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.24 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation’s Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.25 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation’s 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation’s Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |
| 10.1 | Second Amended and R estated C redit A greement dated as of April 27, 2015, among (1) PG&E Corporation , as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC , as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association , as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank , National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Second Amended and R estated C redit A greement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company , as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC , as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. , as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association , as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |

| | | |
|---|---|---|
| 10.4 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.5 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.6 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.7 ) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4 ) |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3) |
| 10.11 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.8 ) |
| 10.12 | * | Performance Share Agreement subject to safety and custom er affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.9 ) |
| 10.13 | * | Performance Share Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5 ) |
| 10.14 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.15 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4) |
| 10.16 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.17 | * | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.18 | * | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |

| | | |
|---|---|---|
| 10.19 | * | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.4) |
| 10.20 | * | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.5) |
| 10.21 | * | Non-Annual Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.6) |
| 10.22 | * | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.7) |
| 10.23 | * | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.8) |
| 10.24 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |
| 10.25 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.26 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7) |
| 10.27 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nickolas Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8) |
| 10.28 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Steven Malnight dated February 22, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2014 (File No. 1-2348), Exhibit 10.3 ) |
| 10.29 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.30 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.31 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.32 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.33 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.3) |

| | | |
|---|---|---|
| 10.34 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.35 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.36 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.37 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.38 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers |
| 10.39 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6 , 2015 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2014) (File No. 1-12609), Exhibit 10. 37 ) |
| 10.40 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.41 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.42 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2016 |
| 10.43 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.44 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.45 | * | Form of Restricted Stock Unit Agreement for 2015 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.46 | * | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 4 ) |
| 10.47 | * | Form of Restrict ed Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Ex hibit 10.2 ) |
| 10.48 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.49 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.50 | * | Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1) |

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| 10.51 | * | Form of Restricted Stock Unit Agreement for 2014 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan ( incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.52 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.53 | * | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 5 ) |
| 10.54 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 6 ) |
| 10.55 | * | Form of Perf ormance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3 ) |
| 10.56 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |
| 10.57 | * | Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2) |
| 10.58 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.59 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.60 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.61 | * | PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5) |
| 10.62 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.63 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.64 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.65 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10. 2 ) |
| 10.66 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.67 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |

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| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23 | | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**NON-ANNUAL RESTRICTED STOCK UNIT GRANT**

**PG&E CORPORATION** , a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2014 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: August 17, 2015

Name of Recipient: Nickolas Stavropoulos

Recipient's Participant ID: XXXXXXXX

Number of Restricted Stock Units: 9,214

***By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock Units dated May 12, 2014.***

***If, for any reason, you wish to not accept this award, please notify PG&E Corporation in writing within 30 calendar days of the date of this award at ATTN: LTIP Administrator at Pacific Gas and Electric Company, 245 Market Street, N2T, San Francisco, 94105.***

Attachment

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**RESTRICTED STOCK UNIT AGREEMENT**

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| **The LTIP and Other Agreements** | This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group. |
| **Grant of Restricted Stock Units** | PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP. |
| **Vesting of Restricted Stock Units** | As long as you remain employed with PG&E Corporation, the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest in accordance with the below vesting schedule ([collectively], the "Normal Vesting Schedule")<br>4,607 on August 17, 2017<br>4,607 on August 17, 2018<br>The amounts payable upon each vesting date are hereby designated separate payments for purposes of Code Section 409A. Except as described below, all Restricted Stock Units subject to this Agreement which have not vested upon termination of your employment shall then be automatically cancelled. As set forth below, the Restricted Stock Units may vest earlier upon the occurrence of certain events. |
| **Dividends** | Restricted Stock Units will accrue Dividend Equivalents in the event cash dividends are paid with respect to PG&E Corporation common stock having a record date prior to the date on which the Restricted Stock Units are settled. Such Dividend Equivalents will be converted into cash and paid, if at all, upon settlement of the underlying Restricted Stock Units. |
| **Settlement** | Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock, subject to the satisfaction of Withholding Taxes, as described below. PG&E Corporation shall issue shares as soon as practicable after the Restricted Stock Units vest in accordance with the Normal Vesting Schedule (but not later than sixty (60) days after the applicable vesting date); provided, however, that such issuance shall, if earlier, be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than sixty (60) days after) the earliest to occur of your (1) Disability (as defined under Code Section 409A), (2) death or (3) "separation from service," within the meaning of Code Section 409A within 2 years following a Change in Control. |
| **Voluntary Termination** | In the event of your voluntary termination, all unvested Restricted Stock Units will be cancelled on the date of termination. |
| **Termination for Cause** | If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause, all unvested Restricted Stock Units will be cancelled on the date of termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation. |
| **Termination other than for Cause** | If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause and you are an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested during the period of the "Severance Multiple" under the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy (as applicable at the time of termination) will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested within the 12 months following such termination had your employment continued will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. All other unvested Restricted Stock Units will be cancelled unless your termination of employment was in connection with a Change in Control as provided below. |
| **Death/Disability** | In the event of your death or Disability while you are employed, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. If your death or Disability occurs following the termination of your employment and your Restricted Stock Units are then outstanding under the terms hereof, then all of your vested Restricted Stock Units plus any Restricted Stock Units that would have otherwise vested during any continued vesting period hereunder shall be settled as soon as practicable after (but not later than sixty (60) days after) the date of your death or Disability. |
| **Termination Due to Disposition of Subsidiary** | (1) If your employment is terminated (other than termination for cause, your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the "Code"), or (2) if your employment is terminated (other than termination for cause, or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest and be settled in the same manner as for a "Termination other than for Cause" described above. |
| **Change in Control** | In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without your consent, either assume or continue PG&E Corporation's rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement.<br>If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your unvested Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and be settled in accordance with the Normal Vesting Schedule, subject to the earlier settlement provisions of this Agreement. |
| **Termination In Connection with a Change in Control** | If you separate from service (other than termination for cause, your voluntary termination) in connection with a Change in Control within three months before the Change in Control occurs, all of your outstanding Restricted Stock Units (including Restricted Stock Units that you would have otherwise forfeited after the end of the continued vesting period) shall automatically vest on the date of the Change in Control and will be settled in accordance with the Normal Vesting Schedule (without regard to the requirement that you be employed) subject to the earlier settlement provisions of this Agreement. In the event of such a separation in connection with a Change in Control within two years following the Change in Control, your Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of such separation and will be settled as soon as practicable after (but not later than sixty (60) days after) the date of such separation. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control |

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| **Delay** | PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain "key employees" of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your "separation from service" under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period. |
| **Withholding Taxes** | The number of shares of PG&E Corporation common stock that you are otherwise entitled to receive upon settlement of Restricted Stock Units will be reduced by a number of shares having an aggregate Fair Market Value, as determined by PG&E Corporation, equal to the amount of any Federal, state, or local taxes of any kind required by law to be withheld by PG&E Corporation in connection with the Restricted Stock Units determined using the applicable minimum statutory withholding rates , including social security and Medicare taxes due under the Federal Insurance Contributions Act and the California State Disability Insurance tax (" Withholding Taxes"). If the withheld shares were not sufficient to satisfy your minimum Withholding Taxes, you will be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Withholding Taxes that is not satisfied by the withholding of shares described above . |
| **Leaves of Absence** | For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."<br>Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a "separation from service" for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months.<br>PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement. |
| **Voting and Other Rights** | You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent). |
| **No Retention Rights** | This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason. |
| **Applicable Law** | This Agreement will be interpreted and enforced under the laws of the State of California. |

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**NON-ANNUAL RESTRICTED STOCK UNIT GRANT**

**PG&E CORPORATION** , a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2014 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: August 17, 2015

Name of Recipient: Geisha Williams

Recipient's Participant ID: XXXXXXXX

Number of Restricted Stock Units: 9,214

***By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock Units dated May 12, 2014.***

***If, for any reason, you wish to not accept this award, please notify PG&E Corporation in writing within 30 calendar days of the date of this award at ATTN: LTIP Administrator at Pacific Gas and Electric Company, 245 Market Street, N2T, San Francisco, 94105.***

Attachment

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**RESTRICTED STOCK UNIT AGREEMENT**

**The LTIP and Other Agreements**

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

**Grant of Restricted Stock Units**

PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP.

**Vesting of Restricted Stock Units**

As long as you remain employed with PG&E Corporation, the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest in accordance with the below vesting schedule ([collectively], the "Normal Vesting Schedule")

4,607 on August 17, 2017
4,607 on August 17, 2018

The amounts payable upon each vesting date are hereby designated separate payments for purposes of Code Section 409A. Except as described below, all Restricted Stock Units subject to this Agreement which have not vested upon termination of your employment shall then be automatically cancelled. As set forth below, the Restricted Stock Units may vest earlier upon the occurrence of certain events.

**Dividends**

Restricted Stock Units will accrue Dividend Equivalents in the event cash dividends are paid with respect to PG&E Corporation common stock having a record date prior to the date on which the Restricted Stock Units are settled. Such Dividend Equivalents will be converted into cash and paid, if at all, upon settlement of the underlying Restricted Stock Units.

**Settlement**

Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock, subject to the satisfaction of Withholding Taxes, as described below. PG&E Corporation shall issue shares as soon as practicable after the Restricted Stock Units vest in accordance with the Normal Vesting Schedule (but not later than sixty (60) days after the applicable vesting date); provided, however, that such issuance shall, if earlier, be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than sixty (60) days after) the earliest to occur of your (1) Disability (as defined under Code Section 409A), (2) death or (3) "separation from service," within the meaning of Code Section 409A within 2 years following a Change in Control.

**Voluntary Termination**

In the event of your voluntary termination, all unvested Restricted Stock Units will be cancelled on the date of termination.

**Termination for Cause**

If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause, all unvested Restricted Stock Units will be cancelled on the date of termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

**Termination other than for Cause**

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause and you are an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested during the period of the "Severance Multiple" under the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy (as applicable at the time of termination) will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested within the 12 months following such termination had your employment continued will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. All other unvested Restricted Stock Units will be cancelled unless your termination of employment was in connection with a Change in Control as provided below.

**Death/Disability**

In the event of your death or Disability while you are employed, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. If your death or Disability occurs following the termination of your employment and your Restricted Stock Units are then outstanding under the terms hereof, then all of your vested Restricted Stock Units plus any Restricted Stock Units that would have otherwise vested during any continued vesting period hereunder shall be settled as soon as practicable after (but not later than sixty (60) days after) the date of your death or Disability.

**Termination Due to Disposition of Subsidiary**

(1) If your employment is terminated (other than termination for cause, your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the "Code"), or (2) if your employment is terminated (other than termination for cause, or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest and be settled in the same manner as for a "Termination other than for Cause" described above.

**Change in Control**

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without your consent, either assume or continue PG&E Corporation's rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement.

If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your unvested Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and be settled in accordance with the Normal Vesting Schedule, subject to the earlier settlement provisions of this Agreement.

**Termination In Connection with a Change in Control**

If you separate from service (other than termination for cause, your voluntary termination) in connection with a Change in Control within three months before the Change in Control occurs, all of your outstanding Restricted Stock Units (including Restricted Stock Units that you would have otherwise forfeited after the end of the continued vesting period) shall automatically vest on the date of the Change in Control and will be settled in accordance with the Normal Vesting Schedule (without regard to the requirement that you be employed) subject to the earlier settlement provisions of this Agreement. In the event of such a separation in connection with a Change in Control within two years following the Change in Control, your Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of such separation and will be settled as soon as practicable after (but not later than sixty (60) days after) the date of such separation. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control

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| **Delay** | PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain "key employees" of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your "separation from service" under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period. |
| **Withholding Taxes** | The number of shares of PG&E Corporation common stock that you are otherwise entitled to receive upon settlement of Restricted Stock Units will be reduced by a number of shares having an aggregate Fair Market Value, as determined by PG&E Corporation, equal to the amount of any Federal, state, or local taxes of any kind required by law to be withheld by PG&E Corporation in connection with the Restricted Stock Units determined using the applicable minimum statutory withholding rates , including social security and Medicare taxes due under the Federal Insurance Contributions Act and the California State Disability Insurance tax (" Withholding Taxes"). If the withheld shares were not sufficient to satisfy your minimum Withholding Taxes, you will be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Withholding Taxes that is not satisfied by the withholding of shares described above . |
| **Leaves of Absence** | For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."<br>Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a "separation from service" for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months.<br>PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement. |
| **Voting and Other Rights** | You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent). |
| **No Retention Rights** | This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason. |
| **Applicable Law** | This Agreement will be interpreted and enforced under the laws of the State of California. |

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**NON-ANNUAL RESTRICTED STOCK UNIT GRANT**

**PG&E CORPORATION** , a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2014 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: August 17, 2015

Name of Recipient: John Simon

Recipient's Participant ID: XXXXXXXX

Number of Restricted Stock Units: 7,371

***By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock Units dated May 12, 2014.***

***If, for any reason, you wish to not accept this award, please notify PG&E Corporation in writing within 30 calendar days of the date of this award at ATTN: LTIP Administrator at Pacific Gas and Electric Company, 245 Market Street, N2T, San Francisco, 94105.***

Attachment

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**RESTRICTED STOCK UNIT AGREEMENT**

**The LTIP and Other Agreements**

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

**Grant of Restricted Stock Units**

PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP.

**Vesting of Restricted Stock Units**

As long as you remain employed with PG&E Corporation, the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest in accordance with the below vesting schedule ([collectively], the "Normal Vesting Schedule")

3,685 on August 17, 2017
3,686 on August 17, 2018

The amounts payable upon each vesting date are hereby designated separate payments for purposes of Code Section 409A. Except as described below, all Restricted Stock Units subject to this Agreement which have not vested upon termination of your employment shall then be automatically cancelled. As set forth below, the Restricted Stock Units may vest earlier upon the occurrence of certain events.

**Dividends**

Restricted Stock Units will accrue Dividend Equivalents in the event cash dividends are paid with respect to PG&E Corporation common stock having a record date prior to the date on which the Restricted Stock Units are settled. Such Dividend Equivalents will be converted into cash and paid, if at all, upon settlement of the underlying Restricted Stock Units.

**Settlement**

Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock, subject to the satisfaction of Withholding Taxes, as described below. PG&E Corporation shall issue shares as soon as practicable after the Restricted Stock Units vest in accordance with the Normal Vesting Schedule (but not later than sixty (60) days after the applicable vesting date); provided, however, that such issuance shall, if earlier, be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than sixty (60) days after) the earliest to occur of your (1) Disability (as defined under Code Section 409A), (2) death or (3) "separation from service," within the meaning of Code Section 409A within 2 years following a Change in Control.

**Voluntary Termination**

In the event of your voluntary termination [(other than Retirement)], all unvested Restricted Stock Units will be cancelled on the date of termination.

**[Retirement**

In the event of your Retirement, unvested Restricted Stock Units will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement; provided, however that in the event of your Retirement within 2 years following a Change in Control, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. Your voluntary termination of employment will be considered to be a Retirement if you are both age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.]

**Termination for Cause**

If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause, all unvested Restricted Stock Units will be cancelled on the date of termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

**Termination other than for Cause**

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause and you are an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested during the period of the "Severance Multiple" under the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy (as applicable at the time of termination) will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested within the 12 months following such termination had your employment continued will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. All other unvested Restricted Stock Units will be cancelled unless your termination of employment was in connection with a Change in Control as provided below.

**Death/Disability**

In the event of your death or Disability while you are employed, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. If your death or Disability occurs following the termination of your employment and your Restricted Stock Units are then outstanding under the terms hereof, then all of your vested Restricted Stock Units plus any Restricted Stock Units that would have otherwise vested during any continued vesting period hereunder shall be settled as soon as practicable after (but not later than sixty (60) days after) the date of your death or Disability.

**Termination Due to Disposition of Subsidiary**

(1) If your employment is terminated (other than termination for cause, [or] your voluntary termination[, or your Retirement]) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the "Code"), or (2) if your employment is terminated (other than termination for cause, [or] your voluntary termination[, or your Retirement]) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest and be settled in the same manner as for a "Termination other than for Cause" described above.

**Change in Control**

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without your consent, either assume or continue PG&E Corporation's rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement.

If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your unvested Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and be settled in accordance with the Normal Vesting Schedule, subject to the earlier settlement provisions of this Agreement.

**Termination In Connection with a Change in Control**

If you separate from service (other than termination for cause, [or] your voluntary termination[, or your Retirement]) in connection with a Change in Control within three months before the Change in Control occurs, all of your outstanding Restricted Stock Units (including Restricted Stock Units that you would have otherwise forfeited after the end of the continued vesting period) shall automatically vest on the date of the Change in Control and will be settled in accordance with the Normal Vesting Schedule (without regard to the requirement

that you be employed) subject to the earlier settlement provisions of this Agreement. In the event of such a separation in connection with a Change in Control within two years following the Change in Control, your Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of such separation and will be settled as soon as practicable after (but not later than sixty (60) days after) the date of such separation. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control

**Delay**

PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain "key employees" of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your "separation from service" under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period.

**Withholding Taxes**

The number of shares of PG&E Corporation common stock that you are otherwise entitled to receive upon settlement of Restricted Stock Units will be reduced by a number of shares having an aggregate Fair Market Value, as determined by PG&E Corporation, equal to the amount of any Federal, state, or local taxes of any kind required by law to be withheld by PG&E Corporation in connection with the Restricted Stock Units determined using the applicable minimum statutory withholding rates , including social security and Medicare taxes due under the Federal Insurance Contributions Act and the California State Disability Insurance tax (" Withholding Taxes"). If the withheld shares were not sufficient to satisfy your minimum Withholding Taxes, you will be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Withholding Taxes that is not satisfied by the withholding of shares described above .

**Leaves of Absence**

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."

Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a "separation from service" for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months.

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

**Voting and Other Rights**

You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent).

**No Retention Rights**

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

**Applicable Law**

This Agreement will be interpreted and enforced under the laws of the State of California.

# Officer Relocation Guide

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# Getting Started

## Your Relocation Guide

PG&E has established this relocation guide to assist in the financial and service needs of employees who meet the eligibility requirements and wish to relocate. The guide is designed to address most events in a typical relocation and is intended to ease the transition to the new location for you and your family.

This guide outlines the various benefits available to you. We suggest that you review it carefully and make note of any questions you have or further information you may need.

## Important Notices

- PG&E reserves the right to interpret, at its sole discretion, the provisions of this program and to amend, limit or change any of its provisions with or without prior notice.

- Nothing in this guide should be interpreted as an employment guarantee or as creating an employment contract, expressed or implied, for any duration.

- The intent of the relocation program is to provide reasonable, consistent and cost effective financial assistance and quality services to employees who relocate. The guide does not offer or imply that all relocation costs will be fully compensated.

- This relocation program has been designed to provide tax benefits and cost savings for you and PG&E. If you choose to work outside the guidelines, certain benefits may not be available to you.

- It is expected that you will make every effort to transfer promptly and control the cost of your move whenever possible. You will be reimbursed for reasonable, necessary and properly authorized eligible expenses. You are expected to maintain expenses at a conservative level and to be familiar with which expenses are reimbursable. The Company may, at its discretion, choose not to reimburse, in full or in part, an expense that is deemed unreasonable or excessive.

# Altair Will Administer Your Relocation

Altair Global is a full-service Relocation Management Company (RMC) retained by PG&E to assist you with each step of your relocation. You will have one single point of contact, your RMC consultant, who will provide service, answer questions, and address any issues that arise.

In addition to normal business hours, your relocation consultant is available evenings and weekends to assist you with any aspect of your relocation.


**Altair Global**
**201 N. Civic Drive, Suite 240**
**Walnut Creek, CA 94596**

**Toll Free: 800.934.5400**
**Direct: 925.945.1001**
**FAX: 925.945.1879**
**www.altairglobal.com**


Altair's Employee and Family web site contains relocation resources, tools, and helpful information. Once the RMC receives your authorization for relocation from PG&E, you will receive an invitation via email to create your account online. You will have access to:

- Relocation policies and related documents
- Online messages about your relocation
- Submit and track expense reimbursement requests

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# Relocation Summary

Please Note: The following summary does not include all details regarding relocation benefits. Conditions and limitations may apply that need further explanation. Do not rely on this summary alone; read the entire document carefully and ask your RMC consultant to clarify any point that you do not understand.

| PROVISION | OFFICER RELOCATION BENEFITS |
|---|---|
| Miscellaneous Expense Allowance | $7,000 (less applicable taxes). |
| Lease Cancellation | Necessary cancellation expenses up to two months' rent. |
| Home Sale Assistance | Includes professional home marketing assistance to support efforts to sell your home and implementation of a home sale assistance process that provides significant tax savings for both you and PG&E when an offer is received from an outside buyer. **You must call your RMC consultant before contacting a broker to list your home.** |
| Guaranteed Purchase Offer (GPO) | The RMC prepares an offer for your home based on the average of two objective appraisals. The GPO may be accepted after your home has been marketed for 60 days. |
| Equity Advance | Equity advance up to 90% of equity based on the GPO. |
| New Home Finding Assistance | Maximum of two trips for a combined total of up to 8 days/7 nights for you and your spouse/registered domestic partner; eligible relocating children may go on one trip. Transportation (baggage fees not covered), lodging and meals (up to $75 per day per adults and children aged 16 and older, and $40 per day per child). Full day rental tour if seeking permanent rental accommodations. |
| Lender Referral | The RMC provides counseling and referral to lenders that offer special programs. |
| Home Purchase Closing Costs | Reimbursement will be equal to actual costs or 2.0% of the new home purchase price, whichever is less. **You must call your RMC consultant before contacting a real estate agent to be eligible for closing cost reimbursement.** |
| Household Goods Moving | Packing, loading, transportation, and insurance; 90 days in-transit storage for authorized household goods; up to 2 cars shipped if move is over 400 miles. |
| Temporary Living Expenses | Up to 6 months of corporate housing; a maximum of 2 round trips or mileage reimbursement for you to return to the departure location OR your spouse/registered domestic partner to visit the destination location. Up to 14 days of rental car while your personal auto is in transit. |
| Final Trip | Reasonable expenses for employee and eligible dependents. Meals (up to $75 per day per adult and children aged 16 and older and $40 per day per child) and lodging reimbursed with original receipts. One-way airfare and baggage fees for up to $100 in total per person if move is over 400 miles; or mileage reimbursed at the current IRS rate. One night's lodging and meals prior to departure, en route, and one night's expenses at destination. |
| Expense Reporting | Employee-paid eligible relocation expenses reimbursed by the RMC upon receiving completed expense form with itemized receipts for all expenses. |
| Tax Liability | Most taxable reimbursements are grossed up to compensate for the tax impact on the employee. Gross-up is provided as a financial benefit, but it is not intended to compensate you completely for all tax liabilities. |

## Eligibility for Benefits

To be eligible for Officer relocation benefits, you must meet the following requirements:

- Your position is Vice President or higher.
- You meet the following Internal Revenue Service (IRS) guidelines for a qualified move for tax purposes.
  - The distance from your former residence to your new work location is 50 miles or greater than the distance from your former residence to your previous work location.
  - You will be employed full time within the same general commuting area for 39 weeks or more within a 12-month period that begins when you arrive at the new location.
- The relocation is between locations within the U.S. or from Canada to the U.S.
- You complete the relocation benefits requirements within twelve (12) months from your hire date or internal transfer date.
- You have signed and returned a relocation repayment agreement to the RMC.

Additionally, if you are a current employee transferring to another location, you must also meet the following requirements:

- You must not have had a relocation paid for by the Company in the last twelve (12) months; and
- The new position must be a regular, full-time position.

## Relocation Repayment Agreement

To be eligible for relocation benefits, employees are required to sign and return a Relocation Repayment Agreement to the RMC. An employee who receives relocation assistance and voluntarily resigns employment within a 24-month period will be required to refund all or part of the monies spent by PG&E, including tax gross-up. Repayment will be as follows:

Resignation within the 1 st year: 100%

Resignation within the 2 nd year: 50%

If you are involuntarily terminated, you will not be responsible for repayment of any relocation expenses, regardless of the duration of employment at the new location.

No relocation benefits, including payments, will be made until a signed copy of the Relocation Repayment Agreement is on file. A copy of the Agreement can be found at the end of this guide.

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## Miscellaneous Expense Allowance

PG&E's relocation program does not cover every expense you are likely to incur during your move. To help you with these various costs, PG&E provides a Miscellaneous Expense Allowance (MEA) of $7,000 (less applicable gross earning taxes—no gross-up is provided).

The MEA is yours to use as you wish, and no receipt submission to the RMC or PG&E is required. However, you may need to keep receipts for your personal tax records. If in doubt, keep your receipts and talk to a tax advisor.

The MEA will be distributed directly to you from the RMC via direct deposit or check once your signed Repayment Agreement has been received and you have started work in your new location. If you are a current employee, you will be responsible for updating your Personnel Change Request in order to receive your MEA.

The MEA may be used to help with expenses such as:

- Storage or shipment of household goods outside of the parameters outlined in this guide
- Alcohol, wine and wine cellar shipment
- Tips to movers
- Travel expenses not covered by relocation guide, e.g., airline upgrade fees, preferred seat fees, baggage fees for the home finding trip, and bags in excess of two per person for the final move trip, etc.
- Concessions negotiated in the sale of a home
- Express mail charges (Federal Express, UPS, Airborne Express, etc.); notary fees, etc.
- Personal telephone calls (long distance, cell phone charges)
- Repairs, decorating, installation, wiring, cleaning, landscaping, etc. expenses for old or new home
- Security or utility deposits
- Automobile registration fees, licenses, or smog control charges
- Losses of fees for subscriptions, memberships, schools, safety deposit box
- Child care expenses
- Spouse/domestic partner employment costs
- Pet deposits or moving and boarding of pets
- Laundry and cleaning
- Tax obligations not fully compensated by gross-up
- GPS and other upgrades not standard for your rental car

## Lease Cancellation

If you are a renter and have a lease to cancel in the departure location, you will be reimbursed for up to 2 months' rent. Your lease must have been signed prior to the date of the official relocation. The intent of this benefit is to cover lease cancellation fees, but not unused rent (i.e. if you are responsible for rent through a given month and move out midway through the month, the balance of that month's rent is not considered reimbursable as "lease cancellation").

Following is the documentation that you will need to submit for reimbursement:

- A copy of the current lease signed by the landlord and tenant(s)
- A copy of the notice to vacate letter that you provided to the landlord or property manager, which includes the date you intend to vacate
- A response back from your landlord with the dollar amount required to break the lease and confirmation that you have vacated and turned in your keys. The landlord will need to outline the costs (i.e. rent, break fee, etc.), associated with breaking the lease.
- Proof of payment of the amount you paid to the landlord for the lease break. This can be in the form of a cancelled check (front and back), credit card or bank statement showing the charge, or a signed/dated receipt from the landlord showing what was paid.

Upload all of the above documents to the website at www.altairglobal.com for reimbursement consideration. Please provide all required documents together to avoid delays in reviewing your reimbursement.

## Relocation Clause

If you decide to rent rather than purchase a home in the new location, you should include a relocation clause in your new lease that allows you to terminate the lease without penalty upon future relocation. The following example may be used:

> It is understood the Lessee is subject to transfer by his or her employer. Accordingly, it is agreed in the event of Lessee's transfer at any time prior to the date on which the last monthly rental payment under this Lease becomes due, Lessor will release Lessee of and from all further obligations under the Lease as of the last day of the monthly rental period during which Lessee vacates the premises, provided the Lessee gives written notice to the Lessor 30 days prior to vacating.

# Home Sale Assistance Program

For homeowners, the sale of your home may be one of the most critical factors in accomplishing a successful relocation. The Home Sale Assistance Program is structured to save money for you and PG&E by providing you the opportunity for significant tax savings.

## You Must Work with Altair

**To receive home sale benefits you must contact PG&E's Relocation Management Company (RMC), Altair, for referral to approved real estate agents in connection with the purchase and/or sale of your residence. If you choose not to use an Altair preferred broker, you may jeopardize your closing cost benefits.**

### Call the Relocation Management Company First!

### 800.934.5400

### 800

## Eligibility of the Home

To be eligible for the Home Sale Assistance Program, your home must meet the following criteria:

- The residence is a one-family or two-family home, townhouse or condominium on a standard size lot (less than one acre) and zoned residential.
- The land on which the residence is located must constitute a lot of standard size for the area and zoned residential. Land not reasonably necessary for the use and enjoyment of the property as a single-family dwelling, such as additional lots or farm acreage, is excluded.
- The home is your primary residence on the effective date of the transfer and you are currently living there.
- You, or you and your spouse/domestic partner, are owner(s) of the property and you have good and marketable title to the property (an ex-spouse/domestic partner or parent cannot be on title).
- The residence is in good and marketable condition.
- The residence is not presently under renovation.
- You know of no hidden or latent defects for which you might later be held responsible.
- Mortgage payments, Real Estate taxes, and Association dues are current.
- All required building permits and private road maintenance agreements are recorded.
- Homes containing a well must have water rights, and the water supply must be both potable and ample under local standards.
- Condominiums must meet the following guidelines:
  - Only twenty percent (20%) of the total number of finished units are vacant and/or unsold.
  - Only twenty percent (20%) of the units are owned by absentee investors for rental purposes.

- Association dues/Assessments per year (net of utilities) do not exceed two percent (2%) of the estimated fair market value of the condominium unit.
- The units in the complex are mortgageable by FNMA standards.
- The Condominium Association is in sound financial condition as evidenced by (I) current financial statements, (II) sufficient replacement reserves, (III) no rapid increase association dues and (IV) no unusual or excessive liens.
- You are responsible for providing verification of the above.

Some properties **may not qualify** for the Home Sale Assistance Program. The following list is not all inclusive, but provides some common examples:

- Unusual homes such as geodesic domes, earth homes, log cabins, houseboats, A-frames, and other specialty homes
- Rural residential zoning or lots larger than one acre
- Cooperative apartments
- Mobile homes and/or trailers
- Residences that require an association's approval of purchaser
- Secondary tracts of land
- Farm properties
- Homes with structural problems to the extent they are deemed, by a qualified structural engineer, to be unsalable
- Homes that are ineligible for standard financing
- Any home built with synthetic stucco; LP, composite, or masonite siding (unless remediated); or containing any other materials which are involved in, or could be potentially involved in, a class action lawsuit
- Homes with toxic mold or excessive levels of hazardous substances
- Vacation homes
- Investment properties
- Apartment buildings

Other factors which may affect the eligibility of a property for this program include, but are not limited to, the following:

- Legal/title problems (liens, judgments)
- Property line issues (properties with private roads must have a recorded road maintenance agreement)
- Structural problems/damage
- Expansive soil
- Safety or code violations
- Unmarketable title
- Inability to meet conventional lender or insurance requirements
- Properties in foreclosure
- Bankruptcy
- Special financing (e.g., first-time buyers)

If your home is subject to any of the items listed above, inform your RMC consultant.

When you request the RMC's assistance, your home must be available for sale. It cannot have been rented or leased within the past 12 months. It cannot be rented or leased after you elect to participate in the Home Sale Assistance Program. All construction and/or repairs must be completed prior to requesting to participate in the Program.

PG&E RETAINS THE RIGHT TO MAKE THE FINAL DECISION ON THE ELIGIBILITY OF A HOME FOR THE HOME SALE ASSISTANCE PROGRAM.

## If your home is ineligible for the Home Sale Assistance Program

In accordance with the criteria identified above, or by the judgment of the RMC and PG&E, you will be responsible for selling your home on your own. You will still receive direct reimbursement for reasonable and customary home sales expenses. **For reference, a list of reasonable and customary home sale expenses covered by PG&E can be found on page 13.** Your home sales expense reimbursement will be grossed up.

## If your home is eligible for the Home Sale Assistance Program

In accordance with the criteria listed above and you choose **not** to participate in the Home Sale Assistance Program, you will still receive reimbursement for reasonable and customary home sale expenses; however, **none of the expenses of the transaction will be grossed up.**

# Step-by-Step Guide to Home Sale Assistance Program

You must follow these steps carefully to ensure compliance with the Home Sale Assistance Program. **If these steps are altered in any way, your home sale assistance benefits may be at risk.**

## Step 1: Speak with your RMC consultant before signing any agreement(s) with real estate professionals regarding the sale of your home.

As soon as PG&E authorizes the RMC to provide services, your consultant will contact you to conduct an initial interview. This interview will include discussion of all aspects of your relocation benefits and the needs that you anticipate for your family during the relocation process.

## Step 2: Broker's Market Analysis

After the initial interview, your consultant will order two Broker's Market Analyses of your home and review them with you. A Broker's Market Analysis (BMA) is performed by a real estate broker on the basis of his or her knowledge of the current real estate resale activity in the community. Each Analysis will compare your home with other similar, recently sold homes to attempt to answer the question:

> "What will the home sell for in the next three to four months, as is, with usual financing for the area?"

The average value of the BMAs will be the basis for the initial listing price for your home under the Home Sale Assistance Program. The home should be listed for no more than 5% over the average of the two BMAs' most probable sales price. (Following the appraisal process, you will need to adjust your list price so that it is not more than 5% over the value provided in your Guaranteed Purchase Offer.) Adherence to the Home Sale Assistance Program requirements, including list price caps, is necessary to receive the home sale assistance and home purchase benefits outlined in this guide.

## Step 3: Selecting a broker or agent to sell your home

You may want to list your home with one of the brokers who provided a BMA, but you are not required to do so. Talk over your broker preferences with your RMC consultant. If you wish to consider additional brokers, the RMC will provide referrals. You are free to choose a broker or agent you already know, subject to RMC approval. Approval must be granted before you take any action regarding the price, terms and service requirements of the listing. In addition, your agent may not be your relative (defined as a parent, child, spouse, domestic partner, sibling, in-law, stepparent, stepchild, grandparent, or grandchild) as it is a conflict of interest for the Company to reimburse members of a relocating family for services (commission) connected with the sale of the old home or purchase of a new home.

## Step 4: Listing your home for sale

After you have chosen a broker or agent, you will be asked to sign a listing agreement. The following "Exclusion Clause" must be included as a signed addendum to your listing agreement:

"It is understood and agreed that regardless of whether or not an offer is presented by a ready, willing and able buyer:

(1) That no commission or compensation is earned by, or is due and payable to, broker until sale of the property has been consummated between seller and buyer, the deed delivered to the buyer and the purchase price delivered to the seller; and

(2) That the seller reserves the right to sell the property to Altair Global or any other person(s) designated by Altair (individually and collectively a "Named Prospective Purchaser") at any time upon which this listing agreement shall terminate without obligation by Altair or the parties to this agreement and no commission or compensation will be due."

**The exclusion clause must be attached to the listing agreement as a signed addendum.** This clause will prevent PG&E from paying the listing broker double commission when the home is sold.

**The commission may not exceed 6% without prior approval from PG&E. The term of any listing agreement should not exceed 90 days.** Your RMC consultant may recommend a shorter term under certain circumstances.

**Establish a realistic list price for the home.** Your RMC consultant will offer advice on the best listing and selling prices, based on current market data provided by real estate professionals in the community. You are encouraged to participate in this process by providing relevant data to the brokers chosen to assess value. The advantages of a competitive listing price will be explained fully by your consultant.

You must complete a home sale disclosure statement. Every home seller has certain legal duties and obligations to a buyer, including full disclosure of all pertinent information about the condition of the home and its surroundings. If the RMC inadvertently or without proper disclosure information purchases a home ineligible for the Home Sale Assistance program, and PG&E incurs a loss as a result of your omission or misrepresentation of information, you must repay PG&E any current and future out-of-pocket expenses, and/or fines or legal judgments paid or to be paid by PG&E with regard to the property.

**You must not sign any purchase offers or accept any earnest money. Your relocation consultant will instruct you on how to proceed.**

## Step 5: Work closely with the broker and the RMC to locate a buyer for your home.

Your RMC consultant will work directly with the real estate broker or agent to monitor progress in marketing your home. The consultant will make constructive suggestions and note any market activity that might impact the sales strategy. You will be contacted regularly by the consultant to discuss current information and revise the sales strategy as needed. You are encouraged to carefully evaluate these recommendations, but you are not required to accept them.

## Step 6: Review any purchase offers on the home with your RMC consultant.

**Signing any purchase offer or accepting any earnest money deposits from a buyer or broker prior to speaking with your RMC consultant will place your Home Sale Assistance benefits at risk.**

You should contact your RMC consultant immediately when you receive any offer to purchase your home. Your consultant is available by phone toll-free during office hours or after hours by calling the number listed on his or her business card, and he or she will tell you what to do if the offer is acceptable to you.

If an offer from a buyer is acceptable, the RMC will sign the contracts. The RMC's obligation to you and PG&E is to determine if the buyer is qualified and if the offer is bona fide before approving the contract.

**It is important to proceed with care in evaluating a purchase offer because some costs may not be reimbursable.** If the buyer's purchase offer requires the seller to pay any concessions or buyer's expenses at closing those costs will be deducted from your equity. The following list provides guidelines for consideration as you negotiate a purchase offer; however, you should consult your RMC consultant if there is any question about whether a cost will be paid under PG&E's relocation benefit program.

| PG&E Will Pay (if normally required of seller) | PG&E Will Not Pay |
|---|---|
| ▪ Document preparation fees<br>▪ Survey fees<br>▪ Mortgage release fees<br>▪ Recording fees<br>▪ Transfer taxes<br>▪ Title insurance<br>▪ Closing and legal fees<br>▪ Escrow fees<br>▪ FHA/VA fees (required by seller)<br>▪ Attorney fees, if an attorney is required to handle the actual closing<br>▪ Termite or pest inspection<br>▪ Radon inspection or warranty, if necessary<br>▪ Normal and reasonable real estate broker's commission (not to exceed 6% of purchase price, unless approved in advance by PG&E) | ▪ Discount points (FHA, VA or conventional)<br>▪ Escrow<br>▪ Insurance<br>▪ Utility bills<br>▪ Property taxes<br>▪ Rent<br>▪ Seller concessions included in the contract with the buyer, including buyer's closing costs, home warranties, repairs, remodeling, restoration or renovation of any kind<br>▪ Expenses to remedy and bring to acceptable standards hazardous conditions in the home, such as:<br>– Radon gas<br>– Friable asbestos<br>– Lead-based paint<br>– Urea formaldehyde foam insulation<br>– Underground storage tanks containing toxic materials<br>– Similar environmental hazards<br>– Pest control |

## Step 7: Amended Value Sale

Amended Value Sale is a procedure that will be used when you find a buyer for your home. The Amended Value Sale Program consists of two separate, arm's length transactions:

- The RMC purchases the home from you at the same net price and terms as the bona fide offer that you have received from a buyer. Once the sale to the RMC closes and you vacate the home, subject to disclosure obligations, you are no longer financially or legally responsible for the home.
- The RMC, as the owner of the property, sells the home at the previously offered price to the buyer who made the offer. If something should happen to prevent this second sale from taking place, you are not affected.

Because the RMC, on behalf of PG&E, is buying your home based on the value of the offer you have received, the RMC must be sure that the offer is bona fide and that the buyer is ready, willing and able to purchase your home. Your consultant will work closely with you and your broker as you consider any offers to be sure that the terms are acceptable to the RMC and PG&E.

In order for an offer to be eligible for the Amended Value Sale Program, it must meet certain requirements, including:

- The contract of sale from the buyer must specify a closing date that is within 60 days of the contract date.
- The contract must not be contingent on the sale of the purchaser's home. It can, however, be contingent on a closing scheduled to occur within thirty (30) days of the contract date.
- The contract must not contain other contingencies, with the exception of inspections and buyer's approval for financing.

If the RMC cannot accept the contract of sale because the buyer is not qualified with a bona fide offer, you must continue to market the home. If you choose to accept the contract of sale with the buyer against the recommendation of the RMC, you will be responsible for managing the process as an independent sale, outside of the Home Sale Assistance Program. In this case, you will still receive direct reimbursement for reasonable and customary home sale expenses; however, **none of the expenses of the transaction will be grossed up.**

## Step 8: Closing an Amended Value Sale

When an acceptable offer to purchase the home has been received, documents previously sent by the RMC will require immediate attention. The documents will include a contract of sale between you and the RMC, certain financial information forms and a general warranty deed that will subsequently be used by the RMC to convey title. Your consultant will offer specific advice as required, but you (and your spouse, if applicable) should plan to execute the documents as soon as possible before a Notary Public and return them to your RMC consultant. It will not be necessary for you to attend the closing of the sale.

You will receive your equity directly from the RMC when the Contract of Sale documents are signed or the property is vacated, whichever is later. Payment will be by either check or electronic transfer. You will also receive a detailed equity statement by email, mail, or fax explaining every adjustment to the equity. In general, the equity will be calculated as follows:

| Guide for Calculation of Equity | |
|---|---|
| To determine the total "net" cash value of any transaction on the home under the Home Sale Assistance Program, first add together: | 1. The purchase price appearing in the RMC's contract of sale, wherein you are the seller and the RMC is the purchaser.<br>2. Any amounts you have prepaid for which you are entitled to receive a prorated refund, such as interest and taxes, but excluding home casualty insurance. |
| Then subtract from the above the total of the following amounts (if any) that are applicable: | 1. All outstanding indebtedness (mortgages, tax liens, judgments, etc.)<br>2. Charges for prorated items such as interest and taxes through the effective date of the contract of sale between you and the RMC or through the vacate date, whichever is later.<br>3. Concessions to which you agreed as the seller.<br>4. Costs for deferred maintenance/repairs to be completed before the home can be purchased.<br>5. A vacate holdback of $500, refundable to you after you have permanently vacated the property and the RMC has verified property condition. |
| The difference is: | The net equity under the Company relocation program. |

## Step 9: Cost of Ownership

The sale price in the Contract of Sale between you and the RMC will reflect the cost of ownership of the home (property insurance, taxes, utilities, maintenance and interest on the mortgage) *through the effective date of the contract of sale between you and the RMC or the vacate date, whichever is later.* The equity statement from the RMC will provide a detailed accounting of your home sale transaction.

It is acceptable to cancel your property insurance as of your vacate or acceptance date, whichever is later. However, for liability purposes it is recommended that your property insurance remain in effect until your new policy is in force **. It is your responsibility to contact your insurance carrier to advise them of cancellation.**

Your RMC consultant will advise you when to discontinue making mortgage and other payments. If you have arrangements with any lender for payments to be automatically deducted from your account, it will be your responsibility to cancel the automatic draft(s) as of your acceptance or vacate date whichever is later. *It is imperative you discuss with your RMC consultant when to send this form to your lender.* If you fail to cancel your automatic draft(s), refunds for overpayments will be delayed until after closing.

## Step 10: Vacating the Home

If you vacate prior to closing, your real estate broker will make arrangements to pick up your house keys, warranties, garage door opener controls and other such necessities. Your consultant will notify you when to transfer utilities to the broker's name, but do not request the utilities be turned off as this will result in reconnect charges. Please be sure to contact the utility companies to provide your forwarding address for your final bills.

Regardless of whether you vacate before or after closing, it will be necessary to leave the home in cleanly swept condition. In order to avoid paying additional cleaning charges later, the home must be clean and you must remove all personal property, trash or debris. Cleaning charges will be withheld from the refund of your "vacate holdback" (Step 8, item 5 in the Guide for Calculation of Equity) if necessary.

## Tax Liability

The majority of expenditures associated with this benefit are not reported as gross earnings; thus no gross-up is necessary provided the home sells under the Amended Value Sale program. The only exception to this is the expenditures associated with the deed and transfer tax of the property in some states.

# Guaranteed Purchase Offer

Once your home is listed under the Home Sale Assistance Program, the RMC will guarantee to purchase your home at a price based on objective relocation appraisals. With this Guaranteed Purchase Offer (GPO), it is possible for you to move with confidence, knowing you may accept the RMC's offer if further marketing under the Home Sale Assistance Program does not bring an acceptable outside buyer.

## Required Marketing Period

You are required to market your home under the Home Sale Assistance Program for 60 days before you may accept the Guaranteed Purchase Offer. The required marketing period begins on the day you list your home for sale under the Home Sale Assistance Program.

## Relocation Appraisals determine the value of the Guaranteed Purchase Offer.

When you have begun to market your home under the Home Sale Assistance Program, you will be asked to select appraisers from a list presented by your RMC consultant. The appraisers will be local, independent appraisers who, once selected, will be hired by the RMC to appraise your home.

The primary intent of PG&E's Home Sale Assistance Program is to assist you in locating a buyer, not to purchase and re-sell your home. Therefore, the appraisers are asked to objectively evaluate your home in order to estimate the **most probable selling price after reasonable market exposure.** This definition of value differs from a bank or mortgage appraisal and may also differ from what a specific buyer might be willing to pay for your home. The GPO is provided as a fall-back offer, available to you if you do not locate a buyer. Through the RMC, PG&E will purchase your home at a price that should enable the RMC to re-sell it within a reasonable amount of time.

You will be thoroughly briefed on the content of the appraisals by your relocation consultant.

The amount of the Guaranteed Purchase Offer will be the average of the two appraisal values. If the lower value of the two appraisals is not within 5% of the higher value, the RMC will ask you to select another appraiser and will order a third appraisal. When this occurs, the Guaranteed Purchase Offer amount will be the average of the *two closest*

*values.* (The Brokers' Market Analyses, discussed previously in the "Home Sale Assistance Program" section, will *not* be included in the average.)

The appraised value is contingent on the results of any customary and required inspections. Repairs identified through these inspections are your financial responsibility. Repairs must be completed before equity is released or the cost of repairs will be deducted from your equity. Repairs are subject to re-inspection. Repairs identified will be defects (i.e., leaks, faulty furnace or water heater, etc.) and do not include cosmetic items such as painting or replacing carpet, unless those items are required by a lender.

In the process of appraising your home, the appraisers will review comparable sales selected from a multiple listing service or similar directory. You are encouraged to provide appraisers with a list of recent, comparable sales or other related data that may be useful in assessing the value of your home.

Within seven days of receiving your Guaranteed Purchase Offer, you must reduce your list price to no more than 105% of the GPO amount. Adherence to the Home Sale Assistance Program guidelines, including list price caps, is necessary to receive the home sale and home purchase benefits outlined in this guide.

## Accepting the Guaranteed Purchase Offer

You may accept the GPO at the end of the 60-day marketing period, or you may continue to market the home until the end of the acceptance period of the GPO. The acceptance period of the GPO is 60 days, beginning with the date of the offer (not necessarily the same date as the marketing period begins).

To accept the GPO, execute the contracts and all associated documents (which may differ depending on which state the home is located). Several of the documents will require the acknowledgment of a Notary Public. All documents must be in the RMC's possession before the end of the 60th day.

The equity payments based on the GPO will be made on the later of either the contract date (when the contract is signed by your relocation consultant) or the date the home is vacated. Allow five (5) business days after the RMC receives paperwork for payment of the equity. The RMC will deliver the equity check to you by overnight service or wire the funds directly to the account.

## Amended Value Sale

If, before accepting your GPO, you receive an offer from an outside buyer that you wish to consider, work with your broker and your RMC consultant to negotiate the offer so that it may be closed as an Amended Value Sale. (See previous discussion of this procedure in the "Home Sale Assistance Program.")

## Home Sale Incentive

Should you receive an offer from an outside buyer that is less than the GPO amount, terms may be negotiated for an amended value sales price that is no less than 95% of the GPO amount. In this case, you may accept this offer and still receive the full amount of the GPO. You will also receive a bonus of 1% of the negotiated sales price, up to a maximum of $10,000, less applicable taxes.

## Possession Period

You will be given thirty (30) days from acceptance of the GPO or Amended Value Sale to vacate the property.

## Proration Date

If you accept the GPO, you will be responsible for insurance, taxes, utilities, maintenance, principal and interest on the mortgage ***through the date of acceptance of the GPO or the date the property is vacated whichever is later.***

## Pass-back of Gain or Loss on Sale to Employee

Under the terms dictated by the Internal Revenue Service, if the employee accepts the GPO and the property ultimately sells for more than the employee's GPO buyout, a pass-back of a gain (or a loss) is not permitted. The sales are treated as two separate sales transactions and cannot be related.

## Tax Liability

The majority of expenditures associated with the GPO benefit are not reported as gross earnings; thus no gross-up is necessary provided the home sells under the Guaranteed Purchase Offer program. The only exception to this is the expenditures associated with the deed and transfer tax of the property in some states.

However, the Home Sale Incentive is reported as additional gross earnings. No tax assistance is available and appropriate taxes will be withheld.

# Equity Advance

The Company may grant you an equity advance in the form of a loan for up to 90% of the equity in your current home when the equity is required to guarantee a contract on a home in the new location. The advance is made to accommodate your being transferred at the request of the Company, and it is not a mortgage loan. The following guidelines apply:

- The advance will equal no more than 90% of the equity based on the Guaranteed Purchase Offer.
- The total amount of the advance must be used exclusively toward the purchase of a new residence.
- You must sign a promissory note and agree to repay the advance upon completion of the sale of the former residence. The term of the promissory note is 120 days.

***If you are an executive of the Company as defined by the Sarbanes-Oxley Act, your equity will be disbursed at the time you accept the Guaranteed Purchase Offer and execute the required paperwork.***

## Tax Liability

This benefit is not reported as gross earnings, and no gross-up is necessary.

# New Home Finding Assistance

**Do not contact any real estate professional at the destination without the guidance of your RMC consultant.** When you are ready to visit your destination to look for suitable housing, the RMC must arrange your travel and lodging and take care of many of the details for you.

PG&E will provide you with assistance in searching for your new residence. Specifically:

- Before you depart to look for housing in the new location, your RMC consultant will ask you for detailed information concerning your housing preferences, price range and family requirements.
- If you wish to rent, the RMC will arrange for a rental service or a real estate broker to assist you in locating the right place for you.
- If you choose to purchase a home, a real estate broker will arrange for house-hunting tours for every day you are in the area. You will be escorted to neighborhoods and homes of interest to you. Through your broker or agent, you will see homes targeted to meet your goals and needs.

## Rental Assistance

In order to assist employees who intend to rent or lease a home or apartment in the new location, one full-day tour with a rental finding company/brokerage will be provided. Your RMC consultant can assign you to a qualified local company in your destination area to provide you with the following information:

- General availability of apartments, houses, and condominiums for rent and the range of rental rates
- Local real estate practices governing such matters as who prepares the lease, the amount of commission if any, and the security deposit required

## Home Search Trip

You and your spouse/registered domestic partner may take up to two home search trips for a maximum of eight days, seven nights total. Dependent children who will be relocating to the destination with the family will also be eligible for one home finding trip.

The following conditions apply to travel expense reimbursement:

- All travel arrangements must be made through the RMC.
- Itemized receipts are required for reimbursement. Submit the Expense Report to the RMC.
- Airline reservations should be made seven days in advance. If you wish to drive, you will be reimbursed mileage at the current IRS rate for business travel.
- Baggage fees are not reimbursable for this trip. You may use your Miscellaneous Allowance to cover baggage fees.
- Expenses for transportation to and from the airport, parking, and tolls will be reimbursed in accordance with the Company business travel policy.
- Reasonable lodging will be provided for employee and spouse/domestic partner together for the trip.
- Expenses for car rental and gas will be reimbursed. Expenses for a GPS or upgrades not standard for the rental car will not be reimbursed.
- Meals up to $75 per day per adults and children aged 16 and older and $40 per day per child under the age of 16. Costs for alcoholic beverages will not be reimbursed.
- Do not use your corporate credit cards for relocation expenses. In addition, do not use your company car for activities related to relocation, as the IRS considers such use as taxable income to you.

## Business Expenses

Should you incur business expenses during the home finding trip, these expenses must be segregated from relocation expenses and submitted to PG&E separately to avoid relocation tax liability.

## Tax Liability

New Home Finding benefits are reported as additional gross earnings and the amount is grossed up to help offset additional taxes.

## Lender Referral

One of the critical aspects of buying a new home is obtaining mortgage financing. The RMC will provide you with a list of representatives of selected local and national mortgage companies that will offer loan programs for your use. You are not required to use any of the lenders referred by the RMC, but they typically offer mortgages at competitive interest rates and reduced fees. Your designated mortgage company will provide details on financing your transaction.

# Home Purchase Closing Costs

You are eligible for reimbursement of normal closing costs when you purchase a home at the new location. To receive this benefit you must close the purchase of your new home within one year of your report date at the destination location. If you choose not to use an Altair preferred broker, you may jeopardize your closing cost benefits .

## Closing Procedures

Your mortgage company will provide details on financing your transaction.

Your consultant will review your closing documents to make certain that the charges are in order, consistent with your negotiated purchase contract and within the limits of reimbursements that will be paid by PG&E.

All eligible costs will be paid by the RMC at closing so that all you need to provide when you close the purchase of your home is the down payment and any concessions or other non-eligible costs.

## Eligible Closing Expenses

Closing costs reimbursement will be equal to actual costs or 2.0% of the new home purchase price, whichever is less.

- Appraisal fee, if required by lending institution
- Credit report
- Settlement or closing fee
- Title insurance
- Document preparation
- Notary fee
- Attorney's fees
- Government recording and transfer charges (only if required of the lender)
- Survey (only if required of the lender)
- General home inspection
- Pest or termite inspection (only if required of the buyer)
- Application fee, commitment fee, processing fee, etc.

*Note:* The items listed above are not all inclusive. Eligible expenses may vary by local custom. Your RMC consultant will advise you regarding expenses covered by PG&E.

## Non-eligible Closing Expenses

Specifically **excluded** from reimbursement are prepaid expenses such as:

- Prorated interest
- Discount points
- Loan origination fees
- Taxes
- Homeowner's insurance
- Mortgage insurance
- Earnest money payments
- Property mortgage insurance for insufficient down money
- Tax or insurance escrow
- Home warranties
- Any fees associated with second mortgages

## Tax Liability

The Closing Cost Benefit is reported as additional gross earnings and the amount is grossed up to help offset additional taxes.

# Household Goods Moving



Your belongings will be shipped by one of the RMC's select moving companies.

Your consultant will arrange for the RMC's household goods move coordinator to contact you and provide you with details surrounding the movement of your household goods. The moving company will need sufficient time to properly coordinate your move. A minimum notice of 30 working days is required. During holidays and summer months, more lead-time is required. Packing and loading dates will be arranged with every attempt made to provide these services on the dates you request. However, keep in mind that PG&E will not authorize or reimburse additional costs of weekend or holiday service. If you request a weekend or holiday move, the overtime charges will be collected directly from you upon delivery.

## Insurance

Replacement cost insurance up to $100,000 is provided at no cost to you. If you require additional coverage in excess of that provided, the cost will be billed to you by the RMC.

## Moving Services

The selected household goods carrier will pack, load, insure, transport, deliver and unpack your normal household goods. There are some limits to this service. Furniture and boxes will be placed in your home where specified, and the contents of your boxes will be unpacked and placed on the closest flat surface, if requested. Unpacking beyond this description is considered a settling-in service or maid service and may be obtained from the moving company at an additional cost to you.

Depending on the complexity of services you require, some additional services may be performed by your moving company or a third-party service firm when deemed necessary by the RMC and within reasonable costs. Such "third-party" services, including crating, will be considered for normal household goods only and will not include service for items affixed to the property.

It is strongly recommended that you take advantage of the packing services provided by this guide. If you pack yourself, no cost saving is realized and none of the goods that you pack will be insured.

If you are unavailable for a pick-up or delivery and do not notify movers in advance, any additional charge will be billed to you.

## Household Goods Storage

Storage of household goods and personal effects in transit will be covered up to 90 days, **but only if storage is unavoidable** . If storage is required for more than 90 days or if you need to access any stored items, the charge will be billed to you.

You will be responsible for costs beyond the time period allowed by this guide.

## Transportation of Automobiles

PG&E will pay for shipping up to two personal automobiles if the move is **greater than 400 miles.** The vehicles must be in working order and must fit on a standard car carrier or moving van. The value of the vehicles to be moved must exceed the cost of shipment.

If the move is less than 400 miles, you are required to drive the cars you own to the new location or ship them at your own expense. Mileage and tolls via the most commonly used direct route will be reimbursed at the current IRS rate.

## Disconnecting and Connecting Appliances/Utilities

PG&E will cover the cost of disconnecting and connecting normal household appliances or any other article requiring special servicing for safe transportation. Appliances include washer, dryer, refrigerator, and icemaker. However, the extension of any gas or electric lines or adding service for mismatched appliances (i.e., converting an electric hook-up for a gas appliance) is excluded.

## Special or Extraordinary Shipping Requirements Are Your Responsibility

Plans should be made in advance for items requiring special or extraordinary handling. These shipping arrangements and the costs will be your responsibility, but call your household goods move coordinator or your relocation consultant for advice.

PG&E will not pay for charges by the moving company to pick up any furnishings or material at any site other than your primary residence. You will be billed directly for this additional service.

## Authorized Household Goods Eligible for Moving Benefit

- Clothing and personal items
- Furniture and fixtures (not attached to the house)
- Major appliances
- Gardening equipment
- Pianos (tuning, servicing and special handling are not included)
- Grandfather clocks
- Pool tables
- Waterbeds (if drained and disassembled)

## Items NOT Authorized

Please refer to the *Domestic Moving Guide* and *Insurance Guide* provided by your household goods move coordinator for a complete list of items that are not eligible for the

moving benefit. The following is a list of items for which PG&E will *not* authorize transportation.

- Boats, trailers, airplanes, motorcycles 250 cc and over, snowmobiles, off-road vehicles, travel trailers, pop-up trailers, camper inserts for pick-up trucks, or other recreational vehicles
- Livestock or domestic animals
- Frozen/perishable foods
- Alcohol, wine and wine cellar shipment
- Liquids in unsafe containers/flammable liquids, items that may contaminate or damage other goods
- Valuable papers/securities/money
- Valuable jewelry/precious stones/firs/items of extraordinary value
- Heavy machinery/tractors/farm equipment larger than normally required for yard and garden maintenance
- Lumber or other building materials
- Plants
- Antiques and fine art
- Animal-drawn carriages or wagons, vintage and show automobiles
- Storage sheds, greenhouses, play houses or other outside buildings
- Campers, motor homes, livestock trailers
- Satellite dishes greater than 24" in diameter/ solar panels
- Coins, stamps and other fine collectibles
- Items associated with an in-home business
- Hot tubs/spas/above-ground pools
- Ammunition and/or explosives
- Firewood/coal
- Items from a temporary residence
- Items that cannot be attached a value (personal paints, pottery, etc.)
- Auto parts
- Any other items which cannot be packed or moved by a standard commercial carrier
- Any goods/materials prohibited by law

*Note:* Gas grills may be shipped but must be emptied and certified before loading.

## Additional Exclusions

- Maid service or housecleaning service
- Tips to movers
- Disassembly/assembly of swimming pools, swing sets, basketball goals, or similar personal property
- Insurance for items of extraordinary value such as antiques, fine art, coin and stamp collections, precious metals, documents, securities and notes, or insurance above the coverage provided by PG&E.
- Disassembly/assembly of play gyms, television/radio antennas, chandeliers, flagpoles, etc. If such items are disassembled prior to packing, they may be transported. **If movers assemble or disassemble unusual items, you will be billed directly** .
- Draining and refilling of waterbeds.
- Establishing services such as power, water, gas, telephones, etc.
- Exclusive use of moving van or space reservation

- Unauthorized extra pick-ups or deliveries
- Unauthorized overtime packing and unpacking
- Unauthorized crating
- Storage of automobiles

## Important Information Concerning Household Goods Shipping

- Valuables such as jewelry, coin and stamp collections, computer programs, currency, precious metals, gems or semi-precious stones, rare documents, or most other collectibles should be set aside and transported with you when you travel. Only under certain very specific conditions is the mover responsible for these items. Be certain to ask the representative of your moving company about transporting valuables when he or she visits your home to inventory your belongings.
- Firearms may be transported, but must be unloaded, packed separately and inventoried by type of firearm and serial number. The inventory must be included in the documentation of the move. This is for your protection as well as the protection of the mover. You will be responsible for meeting the licensing or registration requirements, if any, of the state where you are moving. You cannot ship live ammunition via household goods movers.
- Accompany the mover through the home as he or she inventories and tags each item to be moved. Plan to check off the items at the destination as well; otherwise, you may have difficulty with claims settlements should they prove necessary.
- You or your representative should be present during packing and loading. Do not release the drivers until a complete inspection of the home and property has been accomplished, since items left behind could result in extra charges to you.
- Detach items that are to be moved, such as televisions, wall-mounted can openers and coffee makers, pictures, posters, curtain rods, attached bookcases and the like. Unplug appliances and electrical devices such as stereos and computers; if possible, stow the connecting cords and cables.
- Remove all items from refrigerators. Unplug, defrost, clean and let stand open to dry at least 24 hours in advance of loading.
- Items that cannot be moved by your household goods mover:
  - Bleach
  - Propane tanks or butane tanks
  - Flammable or combustible items of any kind, including gas and oil in lawn mowers, edgers and other yard or utility equipment
  - Open liquids of any kind
  - Frozen foods
  - Aerosol cans or paints
- No mover will accept liability for moving plants. If you choose to allow the mover to move your plants, you do so at your own risk.

  *Note:* Federal regulations require that plants moved interstate be inspected and certified free of pests and diseases. The states of California, Arizona and Florida are especially diligent in enforcing their agriculture laws. Taking plants into these states may require considerable extra expense and effort.
- If you have items in temporary storage, please give the shipper maximum possible advance notice of the date you prefer delivery. Fourteen days is recommended to ensure the availability of your preferred dates.
- Keep your utilities on at the old location until at least the day after the scheduled completion of packing and loading.
- In the event damage occurs during the shipment of your goods, please advise your relocation consultant within 30 days from you final delivery date. All claims must be submitted within 90 days of delivery date.

## Tax Liability

Household goods moving expenses and storage up to 30 days are excluded from gross earnings and no tax liability is created; therefore, gross-up is not necessary. The cost of eligible storage beyond 30 days is grossed up.

# Temporary Living Expenses

If you assume duties at the new location before your new home is available for occupancy, the RMC will arrange for temporary accommodations in corporate housing for up to six months as long as you are still financially responsible for your former residence. Temporary living must be arranged through the RMC.

Only lodging expenses will be covered, this includes one parking space at the temporary housing unit.

If temporary housing that allows pets is available, you are responsible for pet deposits, related fees, etc.

You are eligible for a rental car for up to 14 days while your personal auto is in transit. The rental car can be arranged through Altair's Travel Department and direct billed to Altair.

## Trips Home

The Trip Home benefit is intended to provide you (the employee) with one trip back to your former residence so that you can meet with movers and assist your family with the final move.

You will be eligible for a maximum of two round trips for you, the employee, to return to the departure location OR your spouse/registered domestic partner to visit the destination location. Only round trip airfare or mileage (the most direct route driving at least 400 miles per day) is eligible for reimbursement for your Trip Home benefit. Items that will not be reimbursed include; transportation to and from the airport, parking, meals and baggage fees. The Miscellaneous Expense Allowance is intended to cover these costs.

## Tax Liability

This benefit is reported as additional gross earnings and the amount is grossed up to help offset additional taxes.

# Final Trip

Reimbursement will be provided for reasonable in-transit expenses incurred by you, your spouse/registered domestic partner, and eligible dependents while traveling on the final trip from the old to the new location.

Eligible expenses include reasonable travel, such as a shuttle or taxi to the airport, lodging and meal expenses. Meals up to $75 per day per adults and children aged 16 and older and $40 per day per child under the age of 16. Costs for alcoholic beverages will not be reimbursed.

You must work with your RMC consultant to make your travel arrangements. Air transportation (coach class with advance purchase) will be provided if the distance is over 400 miles; otherwise you are required to drive to the new location. Baggage fees for up to two pieces of regular luggage per person will be eligible for reimbursement. You may be reimbursed for up to $100 in total per person for baggage fees. Any additional baggage fees should be paid for using your Miscellaneous Allowance.

If you drive, you will be reimbursed mileage for up to two automobiles. Mileage reimbursement will be based on the current IRS rate for business travel by the most direct route. Other expenses for hotel and meal reimbursement will be based on travel of at least 400 miles per day. No reimbursement is provided for the additional cost of side trips or sightseeing.

Expenses are reimbursable for one night prior to departure, en route, and if you are unable to move directly into your new home upon arrival, one night at the destination.

Do not use your corporate credit cards for relocation expenses. In addition, do not use your company car for activities related to relocation as the IRS considers such use as taxable income to you.

You must report actual travel expenses on a Relocation Expense Form and submit to the RMC for approval.

## Tax Liability

With the exception of meals and excess mileage in accordance with IRS guidelines, final move expenses are excluded from income and no gross-up is necessary. Meals and excess mileage payments are reported as additional gross earnings and are grossed up.

# Expense Reporting

In some circumstances, you are required to pay certain relocation expenses and request reimbursement afterward. Such reimbursement requests must be kept separate from other business expenses and submitted to the RMC, using the Relocation Expense Form.

After submitting the expense report online, the required receipt copies should be submitted to the RMC for approval and processing **no later than 30 days after you incur the expenses.** Failure to submit expenses within this time frame could jeopardize reimbursement, your tax assistance, or both. Reimbursement will be for actual, reasonable costs only, within the guidelines.

**Please remember:**

- You must include copies of **itemized** receipts for all expenses in order to be eligible for reimbursement.
- You must include a copy of the expense report when you provide your receipts.
- It is wise to make copies of all reimbursement forms and receipts that you submit for your personal records as well as for income tax purposes.

Regular business/travel expenses must be submitted separately to PG&E on separate expense reports.

Do not use your corporate credit cards for relocation expenses. In addition, you may not use your company car for activities related to relocation, as the IRS considers such use as taxable income to you.

In addition to other policy provisions regarding the timing of expense reimbursements, any reimbursements of taxable expenses provided pursuant to this program shall be reimbursed on or before the last day of the calendar year following the year in which the expense was incurred, consistent with requirements in Internal Revenue Code Section 409A, as it may be amended.

The amount of expenses eligible for reimbursement is not subject to a multi-year cap. As a result, expenses eligible for reimbursement during one year do not affect the expenses eligible for reimbursement in any other taxable year.

## Tax Liability on Relocation Expenses Paid to You or On Your Behalf

Most of the amounts expended by PG&E on your behalf during relocation, whether reimbursed to you or paid directly to the service provider, will be included in your annual income. The only exceptions are certain household goods moving and final trip expenses, defined by the IRS, which are *excluded* from your income. Other than these specific, limited exclusions, the total of all other relocation payments will appear on your W-2 issued in January of the following year.

PG&E will provide tax assistance for most taxable benefits through a process called "gross-up." The RMC will calculate the amount of gross-up to which you are entitled and report it to PG&E. PG&E, through the payroll department, will pay additional funds directly to the appropriate tax authority to help offset the tax liability.

Please take note of these important factors pertaining to your gross-up benefits:

- The tax assistance provided by PG&E will be calculated using supplemental federal, state and local rates and will include Social Security and Medicare if applicable.
- Certain relocation expenses, which are not grossed up, may be deductible on your individual tax return.
- Gross-up is provided as a financial benefit, but is not intended to compensate you completely for all tax liabilities.
- You are responsible for calculating, reporting and paying all personal federal, state and local income taxes for which you are liable. The RMC will send you a detailed gross-up package that itemizes all relocation expenses for the tax year, including the gross-up payments the Company provides on your behalf. The package is provided for your information and for use by your tax professional if you use such services.

**The services of tax and legal professionals are recommended.**

# RELOCATION REPAYMENT AGREEMENT

I hereby acknowledge that I have received and read a summary of the relocation assistance benefit available to me under the *Pacific Gas & Electric Company (PG&E)* relocation guide. I understand the benefit to me of the assistance available and agree to the following:

- For purposes of this Agreement, the effective date of relocation is the first day I report to my *PG&E* work location.

- The payment of relocation costs directly to me and to others on my behalf by *PG&E* is conditional upon the successful realization of my physical relocation as requested by *PG&E* and upon my remaining in the employment of *PG&E* for a period of 24 consecutive months from the effective date of relocation. If I voluntarily resign or retire my employment with *PG&E* prior to the completion of 24 consecutive months from the effective date of relocation, I will repay *PG&E* all relocation costs made to me or to others on my behalf, in accordance with the following schedule:

  From the effective date of relocation, if I resign within: 12 months - I will repay 100%

  24 months - I will repay 50%

- If *PG&E* pays relocation costs to me or to others on my behalf but I do not physically relocate as requested by *PG&E* within the specified timeframe, I understand that *PG&E* will recover up to the full amount of relocation costs provided to me or others on my behalf. I understand that if I voluntarily resign or retire my employment with *PG&E* prior to 24 consecutive months from the effective date of my relocation, in addition to notifying my supervisor, I must notify PG&E's Relocation Services Department at relocationservices@pge.com . Relocation Services will inform me of the amount of my relocation repayment obligation within five business days.

- I understand that any relocation repayment obligation I have pursuant to this Agreement is due and payable within 30 days of the notification of my resignation or retirement to relocationservices@pge.com or my last day of work, whichever is earlier. I understand that if I fail to pay *PG&E* the full relocation reimbursement obligation within 30 days of notification of my termination to relocationservices@pge.com , or my final day of work, *PG&E* will submit the debt to a collection agency.

- Any dispute regarding any aspect of this Relocation Repayment Agreement, including its validity, interpretation, or any action which would constitute a violation of this Agreement shall be resolved by an experienced arbitrator, selected by *PG&E* and me (collectively "the parties") in accordance with the rules of the American Arbitration Association. The fees of the arbitrator and cost associated with producing a transcript of the proceedings shall be paid in equal shares by the parties. Any decision rendered by the Arbitrator, including any remedy awarded, shall be in accordance with the laws of California.

- The forum for any dispute submitted to arbitration pursuant to this agreement shall be San Francisco, California. The decision of the arbitrator shall be final and binding. Judgment may be entered thereon in accordance with the practice of any court having jurisdiction.

- Reimbursement of relocation expenses by *PG&E* does not constitute a commitment by *PG&E* with respect to the duration of my employment, or alter my at-will employment status.

- If any of the provisions contained in this agreement is held to be unenforceable, in whole or in part, by a court of competent jurisdiction, the entire agreement shall not fail and all other provisions and obligations of this agreement shall remain valid and enforceable.

**By signing below, I hereby acknowledge and agree to the terms and conditions contained herein and confirm my intent to relocate.**

______________________________
Print Name

______________________________ ________________________
*Employee signature* Date

# PG&E Corporation

# 2014 Long-Term Incentive Plan

# PG&E Corporation
# 2014 Long-Term Incentive Plan

(As adopted effective May 12, 2014, and as amended effective January 1, 2016)

1. **Establishment, Purpose and Term of Plan .**

1.1 **Establishment .** The PG&E Corporation 2014 Long-Term Incentive Plan (the ***" Plan "*** ) is hereby established effective as of the date approved by the shareholders of the Company (the "Effective Date"). This Plan replaces the PG&E Corporation 2006 Long-Term Incentive Plan.

1.2 **Purpose .** The purpose of the Plan is to advance the interests of the Participating Company Group and its shareholders by providing an incentive to attract and retain the best qualified personnel to perform services for the Participating Company Group, by motivating such persons to contribute to the growth and profitability of the Participating Company Group, by aligning their interests with interests of the Company's shareholders, and by rewarding such persons for their services by tying a significant portion of their total compensation package to the success of the Company. The Plan seeks to achieve this purpose by providing for Awards in the form of Options, Stock Appreciation Rights, Restricted Stock Awards, Performance Shares, Performance Units, Restricted Stock Units, Deferred Compensation Awards and other Stock-Based Awards as described below.

1.3 **Term of Plan.** The Plan shall continue in effect until the earlier of its termination by the Board or the date on which no Awards remain outstanding under the Plan. However, the term during which all Awards shall be granted, if at all, shall be within ten (10) years from the Effective Date. Moreover, Incentive Stock Options shall not be granted later than February 19, 2024 (ten (10) years from the date on which the Plan was adopted by the Board).

2. **Definitions and Construction .**

2.1 **Definitions.** Whenever used herein, the following terms shall have their respective meanings set forth below:

(a) ***" Affiliate "*** means (i) an entity, other than a Parent Corporation, that directly, or indirectly through one or more intermediary entities, controls the Company or (ii) an entity, other than a Subsidiary Corporation, that is controlled by the Company directly, or indirectly through one or more intermediary entities. For this purpose, the term "control" (including the term "controlled by") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of the relevant entity, whether through the ownership of voting securities, by contract or otherwise; or shall have such other meaning assigned such term for the purposes of registration on Form S-8 under the Securities Act.

(b) ***" Award "*** means any Option, SAR, Restricted Stock Award, Performance Share, Performance Unit, Restricted Stock Unit or Deferred Compensation Award or other Stock-Based Award granted under the Plan.

(c) ***" Award Agreement "*** means a written agreement between the Company and a Participant setting forth the terms, conditions and restrictions of the Award granted to the Participant (which may also be in electronic form).

(d) ***" Board "*** means the Board of Directors of the Company.

(e) ***" Change in Control "*** means, unless otherwise defined by the Participant's Award Agreement or contract of employment or service, the occurrence of any of the following:

(i) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any benefit plan for Employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act), of stock of the Company representing thirty percent (30%) or more of the combined voting power of the Company's then outstanding voting stock; or

(ii) during any two consecutive years, individuals who at the beginning of such period constitute the Board cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds (2/3) of the Directors then still in office (1) who were Directors at the beginning of the period or (2) whose election or nomination was previously so approved; or

(iii) the consummation of any consolidation or merger of the Company other than a merger or consolidation which would result in the holders of the voting stock of the Company outstanding immediately prior thereto continuing to directly or indirectly hold at least seventy percent (70%) of the Combined Voting Power of the Company, the surviving entity in the merger or consolidation or the parent of such surviving entity outstanding immediately after the merger or consolidation; or

(iv) (1) the consummation of any sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Company, or (2) the approval of the Shareholders of the Company of a plan of liquidation or dissolution of the Company.

For purposes of paragraph (iii), the term ***"Combined Voting Power"*** shall mean the combined voting power of the Company's or other relevant entity's then outstanding voting stock.

(f) ***" Code "*** means the Internal Revenue Code of 1986, as amended, and any applicable regulations promulgated thereunder.

(g) ***" Committee "*** means the Compensation Committee or other committee of the Board duly appointed to administer the Plan and having such powers as shall be specified by the Board. If no committee of the Board has been appointed to administer the Plan, the Board shall exercise all of the powers of the Committee granted herein, and, in any event, the Board may in its discretion exercise any or all of such powers.

(h) ***" Company "*** means PG&E Corporation, a California corporation, or any successor corporation thereto.

(i) ***" Consultant "*** means a person engaged to provide consulting or advisory services (other than as an Employee or a member of the Board) to a Participating Company, provided that the identity of such person, the nature of such services or the entity to which such services are provided would not preclude the Company from offering or selling securities to such person pursuant to the Plan in reliance on registration on a Form S-8 Registration Statement under the Securities Act.

(j) ***" Deferred Compensation Award "*** means an award of Stock Units granted to a Participant pursuant to Section 12 of the Plan.

(k) ***" Director "*** means a member of the Board.

(l) ***" Disability "*** means the permanent and total disability of the Participant, within the meaning of Section 22(e)(3) of the Code, except as otherwise set forth in the Plan or an Award Agreement.

(m) ***" Dividend Equivalent "*** means a credit, made at the discretion of the Committee or as otherwise provided by the Plan, to the account of a Participant in an amount equal to the cash dividends paid on one share of Stock for each share of Stock represented by an Award held by such Participant.

(n) ***" Employee "*** means any person treated as an employee (including an Officer or a member of the Board who is also treated as an employee) in the records of a Participating Company and, with respect to any Incentive Stock Option granted to such person, who is an employee for purposes of Section 422 of the Code; provided, however, that neither service as a member of the Board nor payment of a director's fee shall be sufficient to constitute employment for purposes of the Plan. The Company shall determine in good faith and in the exercise of its discretion whether an individual has become or has ceased to be an Employee and the effective date of such individual's employment or termination of employment, as the case may be. For purposes of an individual's rights, if any, under the Plan as of the time of the Company's determination, all such determinations by the Company shall be final, binding and conclusive, notwithstanding that the Company or any court of law or governmental agency subsequently makes a contrary determination.

(o) ***" Exchange Act "*** means the Securities Exchange Act of 1934, as amended.

(p) ***" Fair Market Value "*** means, as of any date, the value of a share of Stock or other property as determined by the Committee, in its discretion, or by the Company, in its discretion, if such determination is expressly allocated to the Company herein, subject to the following:

(i) Except as otherwise determined by the Committee, if, on such date, the Stock is listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be the closing price of a share of Stock as quoted on the New York Stock Exchange or such other national or regional securities exchange or market system constituting the primary market for the Stock, as reported in *The Wall Street Journal* or such other source as the Company deems reliable. If the relevant date does not fall on a day on which the Stock has traded on such securities exchange or market system, the date on which the Fair Market Value shall be established shall be the last day on which the Stock was so traded prior to the relevant date, or such other appropriate day as shall be determined by the Committee, in its discretion.

(ii) Notwithstanding the foregoing, the Committee may, in its discretion, determine the Fair Market Value on the basis of the opening, closing, high, low or average sale price of a share of Stock or the actual sale price of a share of Stock received by a Participant, on such date, the preceding trading day, the next succeeding trading day or an average determined over a period of trading days. The Committee may vary its method of determination of the Fair Market Value as provided in this Section for different purposes under the Plan.

(iii) If, on such date, the Stock is not listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be as determined by the Committee in good faith without regard to any restriction other than a restriction which, by its terms, will never lapse.

(q) ***" Incentive Stock Option "*** means an Option intended to be (as set forth in the Award Agreement) and which qualifies as an incentive stock option within the meaning of Section 422(b) of the Code.

(r) ***" Insider "*** means an Officer, a Director or any other person whose transactions in Stock are subject to Section 16 of the Exchange Act.

(s) ***"Net-Exercise"*** means a procedure by which the Participant will be issued a number of shares of Stock determined in accordance with the following formula:

X = Y(A-B)/A, where
X = the number of shares of Stock to be issued to the Participant upon exercise of the Option;
Y = the total number of shares with respect to which the Participant has elected to exercise the Option;
A = the Fair Market Value of one (1) share of Stock;
B = the exercise price per share (as defined in the Participant's Award Agreement).

(t) ***" Non-employee Director "*** means a Director who is not an Employee.

(u) ***" Non-employee Director Award "*** means an Award granted to a Non-employee Director pursuant to Section 7 of the Plan.

(v) ***" Nonstatutory Stock Option "*** means an Option not intended to be (as set forth in the Award Agreement) an incentive stock option within the meaning of Section 422(b) of the Code.

(w) ***" Officer "*** means any person designated by the Board as an officer of the Company.

(x) ***" Option "*** means the right to purchase Stock at a stated price for a specified period of time granted to a Participant pursuant to Section 6 or Section 7 of the Plan. An Option may be either an Incentive Stock Option or a Nonstatutory Stock Option.

(y) ***"Option Expiration Date"*** means the date of expiration of the Option's term as set forth in the Award Agreement.

(z) ***" Parent Corporation "*** means any present or future "parent corporation" of the Company in an unbroken chain of corporations ending with the Company in which each of the corporations other than the Company owns stock possessing 50% or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

(aa) ***" Participant "*** means any eligible person who has been granted one or more Awards.

(bb) ***" Participating Company "*** means the Company or any Parent Corporation, Subsidiary Corporation or Affiliate.

(cc) ***" Participating Company Group "*** means, at any point in time, all entities collectively which are then Participating Companies.

(dd) ***" Performance Award "*** means an Award of Performance Shares or Performance Units.

(ee) ***" Performance Award Formula "*** means, for any Performance Award, a formula or table established by the Committee pursuant to Section 10.3 of the Plan which provides the basis for computing the value of a Performance Award at one or more levels of attainment of the applicable Performance Goal(s) measured as of the end of the applicable Performance Period.

(ff) ***" Performance Goal "*** means a performance goal established by the Committee pursuant to Section 10.3 of the Plan.

(gg) ***" Performance Period "*** means a period established by the Committee pursuant to Section 10.3 of the Plan at the end of which one or more Performance Goals are to be measured.

(hh) ***" Performance Share "*** means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Share, as determined by the Committee, based on performance.

(ii) ***" Performance Unit "*** means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Unit, as determined by the Committee, based upon performance.

(jj) ***" Prior Plan "*** means the PG&E Corporation 2006 Long-Term Incentive Plan.

(kk) ***" Restricted Stock Award "*** means an Award of Restricted Stock.

(ll) ***" Restricted Stock Unit"*** or ***" Stock Unit "*** means a bookkeeping entry representing a right granted to a Participant pursuant to Section 11 or Section 12 of the Plan, respectively, to receive a share of Stock or payment equal to the value of a share of Stock on a date determined in accordance with the provisions of Section 11 or Section 12, as applicable, and the Participant's Award Agreement.

(mm) ***" Restriction Period "*** means the period established in accordance with Section 9.4 of the Plan during which shares subject to a Restricted Stock Award are subject to Vesting Conditions.

(nn) ***"Retirement"*** means termination as an Employee with the Participating Company Group at age 55 or older, provided that the Participant was an Employee for at least five consecutive years prior to the date of such termination.

(oo) ***" Rule 16b-3 "*** means Rule 16b-3 under the Exchange Act, as amended from time to time, or any successor rule or regulation.

(pp) ***" SAR "*** or ***" Stock Appreciation Right "*** means a bookkeeping entry representing, for each share of Stock subject to such SAR, a right granted to a Participant pursuant to Section 8 of the Plan to receive payment in any combination of shares of Stock or cash of an amount equal to the excess, if any, of the Fair Market Value of a share of Stock on the date of exercise of the SAR over the exercise price.

(qq) ***" Section 162(m) "*** means Section 162(m) of the Code.

(rr) ***" Section 409A Change in Control "*** means a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation," within the meaning of Section 409A of the Code, as such definition applies to the Company.

(ss) ***" Securities Act "*** means the Securities Act of 1933, as amended.

(tt) ***" Separation from Service "*** means a Participant's "separation from service," within the meaning of Section 409A of the Internal Revenue Code.

(uu) ***" Service "*** means a Participant's employment or service with the Participating Company Group, whether in the capacity of an Employee, a Director or a Consultant. A Participant's Service shall not be deemed to have terminated merely because of a change in the capacity in which the Participant renders such Service or a change in the Participating Company for which the Participant renders such Service, provided that there is no interruption or termination of the Participant's Service. Furthermore, a Participant's Service shall not be deemed to have terminated if the Participant takes any military leave, sick leave, or other bona fide leave of absence approved by the Company. However, if any such leave taken by a Participant exceeds ninety (90) days, then on the ninety-first (91st) day following the commencement of such leave the Participant's Service shall be deemed terminated and any Incentive Stock Option held by the Participant shall cease to be treated as an Incentive Stock Option and instead shall be treated thereafter as a Nonstatutory Stock Option commencing on the third (3 rd ) month from such deemed termination, unless the Participant's right to return to Service with the Participating Company Group is guaranteed by statute or contract. Notwithstanding the foregoing, unless otherwise designated by the Company or required by law, a leave of absence shall not be treated as Service for purposes of determining vesting under the Participant's Award Agreement. A Participant's Service shall be deemed to have terminated either upon an actual termination of Service or upon the entity for which the Participant performs Service ceasing to be a Participating Company. Subject to the foregoing, the Company, in its discretion, shall determine whether the Participant's Service has terminated and the effective date of such termination.

(vv) ***" Stock "*** means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(ww) ***" Stock-Based Awards "*** means any award that is valued in whole or in part by reference to, or is otherwise based on, the Stock, including dividends on the Stock, but not limited to those Awards described in Sections 6 through 12 of the Plan.

(xx) ***" Subsidiary Corporation "*** means any present or future "subsidiary corporation" of the Company in an unbroken chain of corporations beginning with the Company in which each of the corporations other than the last corporation owns stock possessing 50% or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

(yy) " ***Substitute Awards"*** means Awards granted or Shares issued by the Company in assumption of, or in substitution or exchange for, awards previously granted, or the right or obligation to make future awards, in each case by a company acquired by the Company or any Subsidiary Corporation or with which the Company or any Subsidiary Corporation combines.

(zz) ***" Ten Percent Owner "*** means a Participant who, at the time an Option is granted to the Participant, owns stock possessing more than ten percent (10%) of the total combined voting power of all classes of stock of a Participating Company (other than an Affiliate) within the meaning of Section 422(b)(6) of the Code.

(aaa) ***" Vesting Conditions "*** mean those conditions established in accordance with Section 9.4 or Section 11.2 of the Plan prior to the satisfaction of which shares subject to a Restricted Stock Award or Restricted Stock Unit Award, respectively, remain subject to forfeiture or a repurchase option in favor of the Company upon the Participant's termination of Service, or other deadline for satisfying such conditions, as applicable.

2.2 **Construction.** Captions and titles contained herein are for convenience only and shall not affect the meaning or interpretation of any provision of the Plan. Except when otherwise indicated by the context, the singular shall include the plural and the plural shall include the singular. Use of the term "or" is not intended to be exclusive, unless the context clearly requires otherwise.

3. <u>ADMINISTRATION</u> .

3.1 **Administration by the Committee.** The Plan shall be administered by the Committee. All questions of interpretation of the Plan or of any Award shall be determined by the Committee, and such determinations shall be final and binding upon all persons having an interest in the Plan or such Award.

3.2 **Authority of Officers.** Any Officer shall have the authority to act on behalf of the Company with respect to any matter, right, obligation, determination or election which is the responsibility of or which is allocated to the Company herein, provided the Officer has apparent authority with respect to such matter, right, obligation, determination or election. In addition, to the extent specified in a resolution adopted by the Board, the Chief Executive Officer of the Company shall have the authority to grant Awards to an Employee who is not an Insider and who is receiving a salary below the level which requires approval by the Committee; provided that the terms of such Awards conform to guidelines established by the Committee and provided further that at the time of making such Awards the Chief Executive Officer also is a Director.

3.3 **Administration with Respect to Insiders.** With respect to participation by Insiders in the Plan, at any time that any class of equity security of the Company is registered pursuant to Section 12 of the Exchange Act, the Plan shall be administered in compliance with the requirements, if any, of Rule 16b-3.

3.4 **Committee Complying with Section 162(m).** While the Company is a "publicly held corporation" within the meaning of Section 162(m), the Board may establish a Committee of "outside directors" within the meaning of Section 162(m) to approve the grant of any Award which might reasonably be anticipated to result in the payment of employee remuneration that would otherwise exceed the limit on employee remuneration deductible for income tax purposes pursuant to Section 162(m).

3.5 **Powers of the Committee .** In addition to any other powers set forth in the Plan and subject to the provisions of the Plan, the Committee shall have the full and final power and authority, in its discretion:

(a) to determine the persons to whom, and the time or times at which, Awards shall be granted and the number of shares of Stock or units to be subject to each Award based on the recommendation of the Chief Executive Officer of the Company (except that Awards to the Chief Executive Officer shall be based on the recommendation of the independent members of the Board in compliance with applicable stock exchange rules, Non-employee Director Awards shall be granted automatically pursuant to Section 7 of the Plan, and other Awards to Non-employee Directors shall be approved by the Board);

(b) to determine the type of Award granted and to designate Options as Incentive Stock Options or Nonstatutory Stock Options;

(c) to determine the Fair Market Value of shares of Stock or other property;

(d) to determine the terms, conditions and restrictions applicable to each Award (which need not be identical) and any shares acquired pursuant thereto, including, without limitation, (i) the exercise or purchase price of shares purchased pursuant to any Award, (ii) the method of payment for shares purchased pursuant to any Award, (iii) the method for satisfaction of any tax withholding obligation arising in connection with any Award, including by the withholding or delivery of shares of Stock, (iv) the timing, terms and conditions of the exercisability or vesting of any Award or any shares acquired pursuant thereto, (v) the Performance Award Formula and Performance Goals applicable to any Award and the extent to which such Performance Goals have been attained, (vi) the time of the expiration of any Award, (vii) the effect of the Participant's termination of Service on any of the foregoing, and (viii) all other terms, conditions and restrictions applicable to any Award or shares acquired pursuant thereto not inconsistent with the terms of the Plan;

(e) to determine whether an Award will be settled in shares of Stock, cash, or in any combination thereof;

(f) to approve one or more forms of Award Agreement;

(g) to amend, modify, extend, cancel or renew any Award or to waive any restrictions or conditions applicable to any Award or any shares acquired pursuant thereto, subject, in the case of an adversely affected Award, to the affected Participant's consent unless necessary to comply with any applicable law, regulation, or rule;

(h) to accelerate, continue, extend or defer the exercisability or vesting of any Award or any shares acquired pursuant thereto, including with respect to the period following a Participant's termination of Service;

(i) without the consent of the affected Participant and notwithstanding the provisions of any Award Agreement to the contrary, to unilaterally substitute at any time a Stock Appreciation Right providing for settlement solely in shares of Stock in place of any outstanding Option, provided that such Stock Appreciation Right covers the same number of shares of Stock and provides for the same exercise price (subject in each case to adjustment in accordance with Section 4.2) as the replaced Option and otherwise provides substantially equivalent terms and conditions as the replaced Option, as determined by the Committee, and subject to limitations set forth in Section 3.6;

(j) to prescribe, amend or rescind rules, guidelines and policies relating to the Plan, or to adopt sub-plans or supplements to, or alternative versions of, the Plan, including, without limitation, as the Committee deems necessary or desirable to comply with the laws or regulations of or to accommodate the tax policy, accounting principles or custom of, foreign jurisdictions whose citizens may be granted Awards;

(k) to correct any defect, supply any omission or reconcile any inconsistency in the Plan or any Award Agreement and to make all other determinations and take such other actions with respect to the Plan or any Award as the Committee may deem advisable to the extent not inconsistent with the provisions of the Plan or applicable law; and

(l) to delegate to the Chief Executive Officer or the Senior Vice President of Human Resources the authority with respect to ministerial matters regarding the Plan and Awards made under the Plan.

3.6 **Option or SAR Repricing/Buyout.** Notwithstanding anything to the contrary set forth in the Plan, without the affirmative vote of holders of a majority of the shares of Stock cast in person or by proxy at a meeting of the shareholders of the Company at which a quorum representing a majority of all outstanding shares of Stock is present or represented by proxy, the Company shall not approve a program providing for any of the following: (a) the cancellation of outstanding Options or SARs and the grant in substitution therefore of new Options or SARs having a lower exercise price, another Award, cash or a combination thereof (other than in connection with a Change in Control), (b) the amendment of outstanding Options or SARs to reduce the exercise price thereof, (c) the purchase of outstanding unexercised Options or SARs by the Company whether by cash payment or otherwise, or (d) any other action with respect to an Option or SAR that would be treated as a repricing under the rules and regulations of the principal U.S. national securities exchanges on which the Stock is listed. This paragraph shall not be construed to apply to "issuing or assuming a stock option in a transaction to

which section 424(a) applies," within the meaning of Section 424 of the Code. For the avoidance of doubt, this Section 3.6 shall not preclude any action taken without shareholder approval that is described in Section 4.2.

3.7 **Indemnification.** In addition to such other rights of indemnification as they may have as members of the Board or the Committee or as officers or employees of the Participating Company Group, members of the Board or the Committee and any officers or employees of the Participating Company Group to whom authority to act for the Board, the Committee or the Company is delegated shall be indemnified by the Company against all reasonable expenses, including attorneys' fees, actually and necessarily incurred in connection with the defense of any action, suit or proceeding, or in connection with any appeal therein, to which they or any of them may be a party by reason of any action taken or failure to act under or in connection with the Plan, or any right granted hereunder, and against all amounts paid by them in settlement thereof (provided such settlement is approved by independent legal counsel selected by the Company) or paid by them in satisfaction of a judgment in any such action, suit or proceeding, except in relation to matters as to which it shall be adjudged in such action, suit or proceeding that such person is liable for gross negligence, bad faith or intentional misconduct in duties; provided, however, that within sixty (60) days after the institution of such action, suit or proceeding, such person shall offer to the Company, in writing, the opportunity at its own expense to handle and defend the same.

4. **Shares Subject to Plan**.

4.1 **Maximum Number of Shares Issuable.** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan shall be seventeen million (17,000,000) less one share for every one share of Stock covered by an award granted under the Prior Plan after December 31, 2013 and prior to the Effective Date. After the Effective Date, no awards may be granted under the Prior Plan. Shares of Stock issued hereunder shall consist of authorized but unissued or reacquired shares of Stock or any combination thereof. If (i) an outstanding Award for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of Stock acquired pursuant to an Award subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of Stock allocable to the terminated portion of such Award or such forfeited or repurchased shares of Stock shall again be available for issuance under the Plan; or (ii) after December 31, 2013, an outstanding award under the Prior Plan (whenever granted) for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of stock acquired pursuant to an award under the Prior Plan subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of stock allocable to the terminated portion of such award or such forfeited or repurchased shares or stock shall again be available for issuance under the Plan (as of December 31, 2013 there were 6,194,819 shares of stock subject to outstanding awards under the Prior Plan). Shares of Stock shall not be deemed to have been issued pursuant to the Plan (and shall again be available for issuance under the Plan) with respect to any portion of an Award (or, after December 31, 2013, an award under the Prior Plan) that is settled in cash (other than in the case of Options or SARs, in which case shares of Stock having a Fair Market Value equal to the cash delivered shall be deemed issued pursuant to the Plan). Upon the exercise of an SAR (or, after December 31, 2013, exercise of an SAR that was granted under the Prior Plan), the gross number of shares for which the SAR is exercised shall be deemed issued and shall not again be available for issuance under the Plan. In the event that (i) any Option or other Award granted hereunder is exercised through the tendering of shares of Stock (either actually or by attestation) or by the withholding of shares by the Company, or (ii) withholding tax liabilities arising from such Award are satisfied by the tendering of shares of Stock (either actually or by attestation) or by the withholding of shares by the Company, then in each such case (other than in the case of such shares tendered or withheld in connection with the exercise of Options or SARs) the shares of Stock so tendered or withheld shall be added to the shares available for grant under the Plan on a one-for-one basis. In the event that after December 31, 2013, (i) any option or award under the Prior Plan is exercised through the tendering of shares (either actually or by attestation) or by the withholding of shares by the Company, or (ii) withholding tax liabilities arising from such options or awards are satisfied by the tendering of shares (either actually or by attestation) or by the withholding of shares by the Company, then in each such case (other than in the case of such shares tendered or withheld in connection with the exercise of Options or SARs) the shares so tendered or withheld shall be added to the shares available for grant under the Plan on a one-for-one basis.

4.2 **Adjustments for Changes in Capital Structure**. Subject to any required action by the shareholders of the Company, Section 409A of the Code and Section 162(m) of the Code for Awards intended to comply with the "qualified performance-based compensation" exception thereunder, in the event of any change in the Stock effected without receipt of consideration by the Company, whether through merger, consolidation, reorganization, reincorporation, recapitalization, reclassification, stock dividend, stock split, reverse stock split, split-up, split-off, spin-off, combination of shares, exchange of shares, or similar change in the capital structure of the Company, or in the event of payment of a dividend or distribution to the shareholders of the Company in a form other than Stock (excepting normal cash dividends) that has a material effect on the Fair Market Value of shares of Stock, appropriate adjustments shall be made in the number and kind of shares subject to the Plan and to any outstanding Awards, in the Award limits set forth in Section 5.4 , and in the exercise or purchase price per share under any outstanding Award in order to prevent dilution or enlargement of Participants' rights under the Plan. For purposes of the foregoing, conversion of any convertible securities of the Company shall not be treated as "effected without receipt of consideration by the Company." Any fractional share resulting from an adjustment pursuant to this Section 4.2 shall be rounded down to the nearest whole number. The Committee in its sole discretion, may also make such adjustments in the terms of any Award to reflect, or related to, such changes in the capital structure of the Company or distributions as it deems appropriate, including modification of Performance Goals, Performance Award Formulas and Performance Periods, subject to Section 162(m) of the Code for Awards intended to qualify as "performance-based compensation" thereunder. The adjustments determined by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

4.3 **Substitute Awards**. To the extent permitted under the rules of the applicable stock exchange on which the Stock is listed, Substitute Awards shall not reduce the shares of Stock authorized for grant under the Plan, nor shall Shares subject to a Substitute Award be added to the shares of Stock available for Awards under the Plan as provided above. Additionally, subject to the rules of the applicable stock exchange on which the Stock is listed, in the event that a company acquired by the Company or any Subsidiary Corporation or with which the Company or any Subsidiary Corporation combines has shares available under a pre-existing plan approved by shareholders and not adopted in contemplation of such acquisition or combination, the shares available for grant pursuant to the terms of such pre-existing plan (as adjusted, to the extent appropriate, using the exchange ratio or other adjustment or valuation ratio or formula used in such acquisition or combination to determine the consideration payable to the holders of common stock of the entities party to such acquisition or combination) may be used for Awards under the Plan and shall not reduce the shares authorized for grant under the Plan (and shares subject to such Awards shall not be added to the shares available for Awards under the Plan as provided in the paragraphs above); provided that Awards using such available shares shall not be made after the date awards or grants could have been made under the terms of the pre-existing plan, absent the acquisition or combination, and shall only be made to individuals who were not Employees or Directors prior to such acquisition or combination.

5. **Eligibility and Award Limitations**.

5.1 **Persons Eligible for Awards.** Awards may be granted only to Employees, Consultants and Directors (including Non-employee Directors). For purposes of the foregoing sentence, "Employees," "Consultants" and "Directors" shall include prospective Employees, prospective Consultants and prospective Directors to whom Awards are granted in connection with written offers of an employment or other service relationship with the Participating Company Group; provided, however, that no Stock subject to any such Award shall vest, become exercisable or be issued prior to the date on which such person commences Service. A Non-employee Director Award may be granted only to a person who, at the time of grant, is a Non-employee Director.

5.2 **Participation.** Awards other than Non-employee Director Awards are granted solely at the discretion of the Committee. Eligible persons may be granted more than one Award. However , eligibility in accordance with this Section shall not entitle any person to be granted an Award, or, having been granted an Award, to be granted an additional Award.

5.3 **Incentive Stock Option Limitations.**

(a) ***Persons Eligible.*** An Incentive Stock Option ("ISO") may be granted only to a person who, on the effective date of grant, is an Employee of the

Company, a Parent Corporation or a Subsidiary Corporation (each being an " ***ISO-Qualifying Corporation*** "). Any person who is not an Employee of an ISO-Qualifying Corporation on the effective date of the grant of an Option to such person may be granted only a Nonstatutory Stock Option. An Incentive Stock Option granted to a prospective Employee upon the condition that such person become an Employee of an ISO-Qualifying Corporation shall be deemed granted effective on the date such person commences Service with an ISO-Qualifying Corporation, with an exercise price determined as of such date in accordance with Section 6.1.

(b) ***Fair Market Value Limitation.*** To the extent that options designated as Incentive Stock Options (granted under all stock option plans of the Participating Company Group, including the Plan) become exercisable by a Participant for the first time during any calendar year for stock having a Fair Market Value greater than One Hundred Thousand Dollars ($100,000), the portion of such options which exceeds such amount shall be treated as Nonstatutory Stock Options. For purposes of this Section, options designated as Incentive Stock Options shall be taken into account in the order in which they were granted, and the Fair Market Value of stock shall be determined as of the time the option with respect to such stock is granted. If the Code is amended to provide for a limitation different from that set forth in this Section, such different limitation shall be deemed incorporated herein effective as of the date and with respect to such Options as required or permitted by such amendment to the Code. If an Option is treated as an Incentive Stock Option in part and as a Nonstatutory Stock Option in part by reason of the limitation set forth in this Section, the Participant may designate which portion of such Option the Participant is exercising. In the absence of such designation, the Participant shall be deemed to have exercised the Incentive Stock Option portion of the Option first. Upon exercise, shares issued pursuant to each such portion shall be separately identified.

5.4 **Award Limits.**

(a) ***Maximum Number of Shares Issuable Pursuant to Incentive Stock Options.*** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to the exercise of Incentive Stock Options shall not exceed the number of shares set forth in the first sentence of Section 4.1 plus, to the extent allowable under Section 422 of the Code and the Treasury Regulations thereunder, any shares of Stock that again become available for issuance pursuant to the remaining provisions of Section 4.1.

(b) ***Section 162(m) Award Limits.*** Subject to adjustment as provided in Section 4.2, no Participant may be granted (i) Options or Stock Appreciation Rights during any calendar year with respect to more than 800,000 shares of Stock in the aggregate, and (ii) during any calendar year one or more Restricted Stock Awards, Restricted Stock Unit Awards or Performance Share Awards that are intended to comply with the performance-based exception under Code Section 162(m) for more than 1,600,000 shares of Stock in the aggregate; provided that, for this purpose, such limit shall be applied based on the maximum number of shares of Stock that may be earned under the applicable Award(s). During any calendar year no Participant may be granted Performance Units or other Awards that are intended to comply with the performance-based exception under Code Section 162(m) and are denominated in cash under which more than $20,000,000 may be earned in the aggregate. Each of the limitations in this section shall be multiplied by two with respect to Awards granted to a Participant during the first calendar year in which the Participant commences employment with the Company and its Subsidiaries. If an Award is cancelled, the cancelled Award shall continue to be counted toward the applicable limitation in this Section.

(c) ***Non-employee Director Award Limits.*** No Non-employee Director shall be granted Awards (including Non-employee Director Awards) in any calendar year having an aggregate Grant Date value in excess of $400,000. For this purpose, Restricted Stock Units, Restricted Stock Awards, Performance Awards, and other Awards shall be valued based on the Fair Market Value on the Grant Date of the maximum number of shares of Stock or dollars, as applicable, covered thereby and Options and SARs shall be valued using a Black-Scholes or other accepted valuation model, in each case, using reasonable assumptions.

5.5 **Dividends and Dividend Equivalents.** Notwithstanding anything herein to the contrary, cash dividends, stock and any other property (other than cash) distributed as a dividend, a Dividend Equivalent or otherwise with respect to any Award that vests based on achievement of Performance Goals (a) shall either (i) not be paid or credited or (ii) be accumulated, (b) shall be subject to restrictions and risk of forfeiture to the same extent as the underlying Award with respect to which such cash, stock or other property has been distributed and (c) shall be paid after such restrictions and risk of forfeiture lapse in accordance with the terms of the applicable Award Agreement.

6. **Terms and Conditions of Options.**

Options shall be evidenced by Award Agreements specifying the number of shares of Stock covered thereby, in such form as the Committee shall from time to time establish. No Option or purported Option shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Options may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

6.1 **Exercise Price.** The exercise price for each Option shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the Option and (b) no Incentive Stock Option granted to a Ten Percent Owner shall have an exercise price per share less than one hundred ten percent (110%) of the Fair Market Value of a share of Stock on the effective date of grant of the Option. Notwithstanding the foregoing, an Option (whether an Incentive Stock Option or a Nonstatutory Stock Option) may be granted with an exercise price lower than the minimum exercise price set forth above if such Option is granted as a Substitute Award, except as would result in taxation under Section 409A or loss of ISO status.

6.2 **Exercisability and Term of Options.** Options shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such Option; provided, however, that (a) no Option shall be exercisable after the expiration of ten (10) years after the effective date of grant of such Option, (b) no Incentive Stock Option granted to a Ten Percent Owner shall be exercisable after the expiration of five (5) years after the effective date of grant of such Option, and (c) no Option granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service. Subject to the foregoing, unless otherwise specified by the Committee in the grant of an Option, any Option granted hereunder shall terminate ten (10) years after the effective date of grant of the Option, unless earlier terminated in accordance with its provisions.

6.3 **Payment of Exercise Price.**

(a) ***Forms of Consideration Authorized.*** Except as otherwise provided below, payment of the exercise price for the number of shares of Stock being purchased pursuant to any Option shall be made (i) in cash, by check or in cash equivalent, (ii) by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant having a Fair Market Value not less than the exercise price, (iii) by delivery of a properly executed notice of exercise together with irrevocable instructions to a broker providing for the assignment to the Company of the proceeds of a sale or loan with respect to some or all of the shares being acquired upon the exercise of the Option (including, without limitation, through an exercise complying with the provisions of Regulation T as promulgated from time to time by the Board of Governors of the Federal Reserve System) (a " ***Cashless Exercise*** "), (iv) by delivery of a properly executed notice of exercise electing a Net-Exercise, (v) by such other consideration as may be approved by the Committee from time to time to the extent permitted by applicable law, or (vi) by any combination thereof. The Committee may at any time or from time to time grant Options which do not permit all of the foregoing forms of consideration to be used in payment of the exercise price or which otherwise restrict one or more forms of consideration. Notwithstanding the foregoing, an Award Agreement may provide that if on the last day of the term of an Option the Fair Market Value of one share exceeds the option price per share, the Participant has not exercised the Option (or a tandem Stock Appreciation Right, if applicable) and the Option has not expired, the Option, to the extent vested, shall be deemed to have been exercised by the Participant on such day with payment made by withholding shares otherwise issuable in connection with the exercise of the Option. In such event, the Company shall deliver to the Participant the number of shares for which the Option was deemed exercised, less the number of shares required to be withheld for the payment of the total purchase price and required withholding taxes; provided, however, any fractional share shall be settled in cash.

(b) ***Limitations on Forms of Consideration.***

(i) **Tender of Stock.** Notwithstanding the foregoing, an Option may not be exercised by tender to the Company, or attestation to the ownership, of shares of Stock to the extent such tender or attestation would constitute a violation of the provisions of any law, regulation or agreement restricting the redemption of the Company's stock.

(ii) **Cashless Exercise.** The Company reserves, at any and all times, the right, in the Company's sole and absolute discretion, to establish, decline to approve or terminate any program or procedures for the exercise of Options by means of a Cashless Exercise, including with respect to one or more Participants specified by the Company notwithstanding that such program or procedures may be available to other Participants.

6.4 **Effect of Termination of Service.**

(a) ***Option Exercisability .*** Subject to earlier termination of the Option as otherwise provided herein and unless otherwise provided by the Committee, an Option shall be exercisable after a Participant's termination of Service only during the applicable time periods provided in the Award Agreement.

(b) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an Option within the applicable time periods is prevented by the provisions of Section 15 below, the Option shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the Option is exercisable, but in any event no later than the earlier of the Option Expiration Date and the tenth anniversary of the date of grant of the Option.

(c) ***Extension if Exercise Prohibited by Law .*** Notwithstanding the foregoing, in the event that on the last business day of the term of an Option (other than an Incentive Stock Option) the exercise of the Option is prohibited by applicable law, the term of the Option shall be extended for a period of thirty (30) days following the end of the legal prohibition.

7. **Terms and Conditions of Non-employee Director Awards .**

Non-employee Director Awards granted under this Plan shall be automatic and non-discretionary and shall comply with and be subject to the terms and conditions set forth in this Section 7.

The grant date for all Non-employee Director awards to be made under this Section 7 shall be the later of (1) the date on which the independent inspector of election certifies the results of the annual election of directors by shareholders of PG&E Corporation or (2) the date that this Plan becomes effective and grants can be made consistent with legal requirements; provided, however, that in extraordinary circumstances, the grant shall be delayed until the first business day of the next open trading window period following certification of the director election results, as determined by the General Counsel of PG&E Corporation (the "Grant Date").

Grants made pursuant to this Section 7, but prior to January 1, 2015, shall be subject to the terms of Section 7 of the Prior Plan as in effect prior to the Effective Date, provided, however, that such grants shall be deemed made under this Plan.

7.1 **Grant of Restricted Stock Unit.**

(a) Timing and Amount of Grant. Each person who is a Non-employee Director on the Grant Date shall receive a grant of Restricted Stock Units with the number of Restricted Stock Units determined by dividing $140,000 by the Fair Market Value of the Stock on the Grant Date (rounded down to the nearest whole Restricted Stock Unit). The Restricted Stock Units awarded to a Non-employee Director shall be credited to the director's Restricted Stock Unit account. Each Restricted Stock Unit awarded to a Non-employee Director in accordance with this Section 7.1(a) shall be deemed to be equal to one (1) (or fraction thereof) share of Stock on the Grant Date, and the value of the Restricted Stock Unit shall thereafter fluctuate in value in accordance with the Fair Market Value of the Stock. No person shall receive more than one grant of Restricted Stock Units pursuant to this Section 7.1(a) during any calendar year.

(b) ***Dividend Rights*** . Each Non-employee Director's Restricted Stock Unit account shall be credited quarterly on each dividend payment date with additional shares of Restricted Stock Units (including fractions computed to three decimal places) determined by dividing (1) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the account by (2) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award.

(c) ***Settlement of Restricted Stock Units*** . Restricted Stock Units credited to a Non-employee Director's Restricted Stock Unit account shall, to the extent vested, be settled in a lump sum by the issuance of an equal number of shares of Stock, rounded down to the nearest whole share, upon the earliest of (i) the first anniversary of the Grant Date (normal vesting date), (ii) the Non-employee Director's death, (iii) the Non-employee Director's Disability (within the meaning of Section 409A of the Code), or (iv) the Non-employee Director's Separation from Service following a Change in Control. However, commencing with Restricted Stock Units having a Grant Date in 2015, a Non-employee Director may irrevocably elect, no later than December 31 of the calendar year prior to the Grant Date of the Restricted Stock Units (or such later time permitted by Section 409A) to have the Non-employee Director's Restricted Stock Unit account settled in (1) a series of 10 approximately equal annual installments (which shall be separate payments for purposes of Section 409A) commencing in January of any year following the normal vesting date, or (2) a lump sum in January of any future year following the normal vesting date. In the event that the Non-employee Director elects settlement of the Restricted Stock Units in accordance with the immediately preceding sentence, the Restricted Stock Units shall be earlier settled in a lump sum, to the extent vested, upon the occurrence of any of the events set forth in Section 7.1(c)(ii) through 7.1(c)(iv) prior to the elected settlement date (or commencement thereof in the case of settlement in 10 equal annual installments). In the event that a Non-employee Director elects to have the Non-employee Director's Restricted Stock Unit account settled in a series of 10 approximately equal annual installments commencing in January of any year following the normal vesting date and one of the events set forth in Section 7.1(c)(ii) through 7.1(c)(iv) occurs after commencement of such installments but prior to full settlement of the Non-employee Director's Restricted Stock Units, then any remaining unsettled Restricted Stock Units will be settled in a lump sum upon the occurrence of the applicable event but only to the extent that such acceleration would not result in the imposition of taxation under Section 409A.

7.2 **Effect of Termination of Service as a Non-employee Director.**

(a) ***Forfeiture of Award .*** If the Non-employee Director has a Separation from Service prior to the normal vesting date, all Restricted Stock Units credited to the Participant's account that have not vested in accordance with Section 7.2(b) or 7.3 shall be forfeited to the Company and from and after the date of such Separation from Service, and the Participant shall cease to have any rights with respect thereto; provided, however, that if the Non-employee Director Separates from Service due to a pending Disability determination, such forfeiture shall not occur until a finding that such Disability has not occurred.



(b) ***Death or Disability*** . If the Non-employee Director becomes "disabled," within the meaning of Section 409A of the Code or in the event of the Non-

employee Director's death, all Restricted Stock Units credited to the Non-employee Director's account shall immediately vest and become payable, in accordance with Section 7.1(c), to the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock Units by reason of the Participant's death) in the form of a number of shares of Stock equal to the number of Restricted Stock Units credited to the Restricted Stock Unit account, rounded down to the nearest whole share.

(c) Notwithstanding the provisions of Section 7.1(c) above, the Board, in its sole discretion, may amend this Section 7 or establish different terms and conditions pertaining to Non-employee Director Awards.

7.3 **Effect of Change in Control on Non-employee Director Awards.** In the event a Non-employee Director ceases to be on the Board for any reason (other than resignation), following the occurrence of a Change in Control, all Restricted Stock Units shall immediately vest but shall not be settled until such time set forth in Section 7.1(c) occurs.

7.4 **Other Awards to Non-employee Directors** . Notwithstanding anything to the contrary set forth in this Plan, subject to Section 5.4(c) of the Plan, Non-employee Directors shall be eligible to receive all types of Awards under the Plan in addition to or instead of Non-employee Director Awards, as may be determined by the Board.

8. **Terms and Conditions of Stock Appreciation Rights .**

Stock Appreciation Rights shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No SAR or purported SAR shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing SARs may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

8.1 **Types of SARs Authorized.** SARs may be granted in tandem with all or any portion of a related Option (a *" Tandem SAR "* ) or may be granted independently of any Option (a *" Freestanding SAR "* ). A Tandem SAR may be granted either concurrently with the grant of the related Option or at any time thereafter prior to the complete exercise, termination, expiration or cancellation of such related Option.

8.2 **Exercise Price.** The exercise price for each SAR shall be established in the discretion of the Committee; provided, however, that (other than in connection with Substitute Awards granted in accordance with Code Section 424(a)): (a) the exercise price per share subject to a Tandem SAR shall be the exercise price per share under the related Option and (b) the exercise price per share subject to a Freestanding SAR shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the SAR.

8.3 **Exercisability and Term of SARs.**

(a) ***Tandem SARs.*** Tandem SARs shall be exercisable only at the time and to the extent, and only to the extent, that the related Option is exercisable, subject to such provisions as the Committee may specify where the Tandem SAR is granted with respect to less than the full number of shares of Stock subject to the related Option.

(b) ***Freestanding SARs.*** Freestanding SARs shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such SAR; provided, however, that no Freestanding SAR shall be exercisable after the expiration of ten (10) years after the effective date of grant of such SAR.

(c) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an SAR within the applicable time periods is prevented by the provisions of Section 15 below, the SAR shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the SAR is exercisable, but in any event no later than the earlier of the date of expiration of the SAR's term (as set forth in the applicable Award Agreement) and the tenth anniversary of the date of grant of the SAR.

(d) ***Extension if Exercise Prohibited by Law .*** Notwithstanding the foregoing, in the event that on the last business day of the term of an SAR the exercise of the SAR is prohibited by applicable law, the term shall be extended for a period of thirty (30) days following the end of the legal prohibition.

8.4 **Deemed Exercise of SARs.** An Award Agreement may provide that if on the last day of the term of an SAR the Fair Market Value of one share exceeds the grant price per share of the Stock Appreciation Right, the Participant has not exercised the SAR or the tandem Option (if applicable), and the SAR has not otherwise expired, the SAR, to the extent then vested, shall be deemed to have been exercised by the Participant on such day. In such event, the Company shall make payment to the Participant in accordance with this Section, reduced by the number of shares (or cash) required for withholding taxes; any fractional share shall be settled in cash.

8.5 **Effect of Termination of Service.** Subject to earlier termination of the SAR as otherwise provided herein and unless otherwise provided by the Committee in the grant of an SAR and set forth in the Award Agreement, an SAR shall be exercisable after a Participant's termination of Service only as provided in the Award Agreement.

9. **Terms and Conditions of Restricted Stock Awards .**

Restricted Stock Awards shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Award or purported Restricted Stock Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

9.1 **Types of Restricted Stock Awards Authorized.** Restricted Stock Awards may or may not require the payment of cash compensation for the stock. Restricted Stock Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 or other performance conditions established by the Committee. If either the grant of a Restricted Stock Award or the lapsing of the Restriction Period is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m) of the Code.

9.2 **Purchase Price.** The purchase price, if any, for shares of Stock issuable under each Restricted Stock Award and the means of payment shall be established by the Committee in its discretion.

9.3 **Purchase Period.** A Restricted Stock Award requiring the payment of cash consideration shall be exercisable within a period established by the Committee; provided, however, that no Restricted Stock Award granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service.

9.4 **Vesting and Restrictions on Transfer.** Shares issued pursuant to any Restricted Stock Award may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award. During any Restriction Period in which shares acquired pursuant to a Restricted Stock Award remain subject to Vesting Conditions, such shares may not be sold, exchanged, transferred, pledged, assigned or otherwise disposed of other than as provided in the Award Agreement or as provided in Section 18. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

9.5 **Voting Rights, Dividends and Distributions.** Except as provided in this Section, Section 9.4, Section 5.5, and any Award Agreement, during the Restriction Period applicable to shares subject to a Restricted Stock Award, the Participant shall have all of the rights of a shareholder of the Company holding shares of Stock, including the right to vote such shares and to receive all dividends and other distributions paid with respect to such shares. However, in the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant is entitled by reason of the Participant's Restricted Stock Award shall be immediately subject to the same Vesting Conditions as the shares subject to the Restricted Stock Award with respect to which such dividends or distributions were paid or adjustments were made.

9.6 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any shares acquired by the Participant pursuant to a Restricted Stock Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service in exchange for the payment of the purchase price, if any, paid by the Participant. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company.

10. **Terms and Conditions of Performance Awards .**

Performance Awards shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No Performance Award or purported Performance Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Performance Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions to the extent required under Section 162(m). Notwithstanding the foregoing, Awards that are not intended to comply with the "qualified performance-based compensation" exception under Section 162(m) may be subject to such other terms and conditions (which may be different from the terms and conditions set forth in this Section 10) as shall be determined by the Committee in its sole discretion.

10.1 **Types of Performance Awards Authorized.** Performance Awards may be in the form of either Performance Shares or Performance Units. Each Award Agreement evidencing a Performance Award shall specify the number of Performance Shares or Performance Units subject thereto, the Performance Award Formula, the Performance Goal(s) and Performance Period applicable to the Award, and the other terms, conditions and restrictions of the Award.

10.2 **Initial Value of Performance Shares and Performance Units.** Unless otherwise provided by the Committee in granting a Performance Award, each Performance Share shall have an initial value equal to the Fair Market Value of one (1) share of Stock, subject to adjustment as provided in Section 4.2, on the effective date of grant of the Performance Share. Each Performance Unit shall have an initial value determined by the Committee. The final value payable to the Participant in settlement of a Performance Award determined on the basis of the applicable Performance Award Formula will depend on the extent to which Performance Goals established by the Committee are attained within the applicable Performance Period established by the Committee.

10.3 **Establishment of Performance Period, Performance Goals and Performance Award Formula.** In granting each Performance Award, the Committee shall establish in writing the applicable Performance Period, Performance Award Formula and one or more Performance Goals which, when measured at the end of the Performance Period, shall determine on the basis of the Performance Award Formula the final value of the Performance Award to be paid to the Participant. To the extent compliance with the requirements under Section 162(m) with respect to "performance-based compensation" is desired, the Committee shall establish the Performance Goal(s) and Performance Award Formula applicable to each Performance Award no later than the earlier of (a) the date ninety (90) days after the commencement of the applicable Performance Period or (b) the date on which 25% of the Performance Period has elapsed, and, in any event, at a time when the outcome of the Performance Goals remains substantially uncertain. Once established, the Performance Goals and Performance Award Formula for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m) shall not be changed during the Performance Period, except as would result in the exercise of negative discretion by the Committee to reduce the amount of the Award otherwise payable as permitted under Section 162(m). The Company shall notify each Participant granted a Performance Award of the terms of such Award, including the Performance Period, Performance Goal(s) and Performance Award Formula.

10.4 **Measurement of Performance Goals.** Performance Goals shall be established by the Committee on the basis of targets to be attained ( ***" Performance Targets "*** ) with respect to one or more measures of business or financial performance (each, a ***" Performance Measure "*** ), subject to the following:

(a) ***Performance Measures.*** Performance Measures shall be calculated with respect to the Company and/or each Subsidiary Corporation and/or such division or other business unit as may be selected by the Committee, or may be based upon performance relative to performance of other companies or upon comparisons of any of the indicators of performance relative to performance of other companies. Performance Measures may be based upon one or more of the following objectively defined and non-discretionary business criteria and any other objectively verifiable and non-discretionary adjustments permitted and pre-established by the Committee in accordance with Section 162(m), as determined by the Committee: (i) sales revenue; (ii) gross margin; (iii) operating margin; (iv) operating income; (v) pre-tax profit; (vi) earnings before interest, taxes and depreciation and amortization (EBITDA)/adjusted EBITDA; (vii) net income; (viii) expenses; (ix) the market price of the Stock; (x) earnings per share; (xi) return on shareholder equity or assets; (xii) return on capital; (xiii) return on net assets; (xiv) economic profit or economic value added (EVA); (xv) market share; (xvi) customer satisfaction; (xvii) safety; (xviii) total shareholder return; (xix) earnings; (xx) cash flow; (xxi) revenue; (xxii) profits before interest and taxes; (xxiii) profit/loss; (xxiv) profit margin; (xxv) working capital; (xxvi) price/earnings ratio; (xxvii) debt or debt-to-equity; (xxviii) accounts receivable; (xxix) write-offs; (xxx) cash; (xxxi) assets; (xxxii) liquidity; (xxxiii) earnings from operations; (xxxiv) operational reliability; (xxxv) environmental performance; (xxxvi) funds from operations; (xxxvii) adjusted revenues; (xxxviii) free cash flow; (xxxix) core earnings; or (xxxx) operational performance.

(b) ***Performance Targets.*** Performance Targets may include a minimum, maximum, target level and intermediate levels of performance, with the final value of a Performance Award determined under the applicable Performance Award Formula by the level attained during the applicable Performance Period. A Performance Target may be stated as an absolute value or as a value determined relative to a standard selected by the Committee.

10.5 **Settlement of Performance Awards.**

(a) ***Determination of Final Value.*** As soon as practicable, but no later than the 15th day of the third month following the completion of the Performance Period applicable to a Performance Award (or such shorter period set forth in an Award Agreement), the Committee shall certify in writing the extent to which the applicable Performance Goals have been attained and the resulting final value of the Award earned by the Participant and to be paid upon its settlement in accordance with the applicable

Performance Award Formula no later than the 15 th day of the third month following the completion of such Performance Period (or such shorter period set forth in an Award Agreement).

(b) ***Discretionary Adjustment of Award Formula.*** In its discretion, the Committee may, either at the time it grants a Performance Award or at any time thereafter, provide for the positive or negative adjustment of the Performance Award Formula applicable to a Performance Award that is not intended to constitute "qualified performance-based compensation" to a "covered employee" within the meaning of Section 162(m) (a ***" Covered Employee "*** ) to reflect such Participant's individual performance in his or her position with the Company or such other factors as the Committee may determine. With respect to a Performance Award intended to constitute qualified performance-based compensation to a Covered Employee, the Committee shall have the discretion to reduce (but not increase) some or all of the value of the Performance Award that would otherwise be paid to the Covered Employee upon its settlement notwithstanding the attainment of any Performance Goal and the resulting value of the Performance Award determined in accordance with the Performance Award Formula.

(c) ***Payment in Settlement of Performance Awards.*** As soon as practicable following the Committee's determination and certification in accordance with Sections 10.5(a) and (b) but, in any case, no later than the 15th day of the third month following completion of the Performance Period applicable to a Performance Award (or such shorter period set forth in an Award Agreement), payment shall be made to each eligible Participant (or such Participant's legal representative or other person who acquired the right to receive such payment by reason of the Participant's death) of the final value of the Participant's Performance Award. Payment of such amount shall be made in cash, shares of Stock, or a combination thereof as determined by the Committee.

10.6 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Performance Share Awards until the date of the issuance of such shares, if any (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Performance Share Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which the Performance Shares are settled or forfeited. Such Dividend Equivalents, if any, shall be credited to the Participant in the form of additional whole Performance Shares as of the date of payment of such cash dividends on Stock. The number of additional Performance Shares (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Performance Shares previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Dividend Equivalents credited in connection with Performance Shares shall be subject to Section 5.5 of the Plan. Settlement of Dividend Equivalents may be made in cash, shares of Stock, or a combination thereof as determined by the Committee, and may be paid on the same basis as settlement of the related Performance Share as provided in Section 10.5. Dividend Equivalents shall not be paid with respect to Performance Units. In the event of an adjustment described in Section 4.2, the adjusted Performance Share Award shall be immediately subject to the same Performance Goals as are applicable to the Award.

10.7 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Performance Award and set forth in the Award Agreement, the effect of a Participant's termination of Service on the Performance Award shall be as follows:

(a) ***Death or Disability.*** If the Participant's Service terminates because of the death or Disability of the Participant before the completion of the Performance Period applicable to the Performance Award, the final value of the Participant's Performance Award shall be determined by the extent to which the applicable Performance Goals have been attained with respect to the entire Performance Period and shall be prorated based on the number of months of the Participant's Service during the Performance Period. Payment shall be made following the end of the Performance Period in any manner permitted by Section 10.5.

(b) ***Other Termination of Service.*** If the Participant's Service terminates for any reason except death or Disability before the completion of the Performance Period applicable to the Performance Award, such Award shall be forfeited in its entirety; provided, however, that in the event of termination of the Participant's Service for other reasons, the Committee, in its sole discretion, may waive the automatic forfeiture of all or any portion of any such Award, to the extent consistent with the preservation of the tax deductibility of awards pursuant to Section 162(m) of the Code.

11. TERMS AND CONDITIONS OF RESTRICTED STOCK UNIT AWARDS .

Restricted Stock Unit Awards shall be evidenced by Award Agreements specifying the number of Restricted Stock Units subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Unit Award or purported Restricted Stock Unit Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Units may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

11.1 **Grant of Restricted Stock Unit Awards.** Restricted Stock Unit Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4. If either the grant of a Restricted Stock Unit Award or the Vesting Conditions with respect to such Award is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m).

11.2 **Vesting.** Restricted Stock Units may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award.

11.3 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Restricted Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Restricted Stock Unit Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Restricted Stock Units held by such Participant are settled. Such Dividend Equivalents, if any, shall be paid by crediting the Participant with additional whole Restricted Stock Units as of the date of payment of such cash dividends on Stock. The number of additional Restricted Stock Units (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award, provided that Dividend Equivalents may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee and set forth in the Award Agreement. In the event of an adjustment as described in Section 4.2, the Participant's adjusted Restricted Stock Unit Award shall be immediately subject to the same Vesting Conditions as are applicable to the Award.

11.4 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Unit Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any Restricted Stock Units pursuant to the Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service.

11.5 **Settlement of Restricted Stock Unit Awards.** The Company shall issue to a Participant on the date on which Restricted Stock Units subject to the

Participant's Restricted Stock Unit Award vest or on such other date determined by the Committee, in its discretion, and set forth in the Award Agreement one (1) share of Stock (and/or any other new, substituted or additional securities or other property pursuant to an adjustment described in Section 11.3) for each Restricted Stock Unit then becoming vested or otherwise to be settled on such date, subject to the withholding of applicable taxes, provided that Restricted Stock Units may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee and set forth in the Award Agreement. Notwithstanding the foregoing, if permitted by the Committee and set forth in the Award Agreement and subject to the restrictions of Section 409A of the Code, the Participant may elect in accordance with terms specified in the Award Agreement to defer receipt of all or any portion of the shares of Stock or other property otherwise issuable to the Participant pursuant to this Section.

12. **DEFERRED COMPENSATION AWARDS .**

12.1 **Establishment of Deferred Compensation Award Programs.** This Section 12 shall not be effective unless and until the Committee determines to establish a program pursuant to this Section. The Committee, in its discretion and upon such terms and conditions as it may determine, may establish one or more programs pursuant to the Plan under which:

(a) Subject to the restrictions of Section 409A of the Code, Participants designated by the Committee who are Insiders or otherwise among a select group of management or highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to reduce such Participant's compensation otherwise payable in cash (subject to any minimum or maximum reductions imposed by the Committee) and to be granted automatically at such time or times as specified by the Committee one or more Awards of Stock Units with respect to such numbers of shares of Stock as determined in accordance with the rules of the program established by the Committee and having such other terms and conditions as established by the Committee.

(b) Subject to the restrictions of Section 409A of the Code, Participants designated by the Committee who are Insiders or otherwise among a select group of management or highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to be granted automatically an Award of Stock Units with respect to such number of shares of Stock and upon such other terms and conditions as established by the Committee in lieu of cash or shares of Stock otherwise issuable to such Participant upon the settlement of a Performance Award or Performance Unit.

12.2 **Terms and Conditions of Deferred Compensation Awards.** Deferred Compensation Awards granted pursuant to this Section 12 shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No such Deferred Compensation Award or purported Deferred Compensation Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Deferred Compensation Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

(a) ***Vesting Conditions*** . Deferred Compensation Awards shall or shall not be subject to vesting conditions, as determined by the Committee.

(b) ***Terms and Conditions of Stock Units*** .

(i) **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the applicable Award Agreement that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Stock Units held by such Participant are settled. Such Dividend Equivalents shall be paid by crediting the Participant with additional whole and/or fractional Stock Units as of the date of payment of such cash dividends on Stock. The method of determining the number of additional Stock Units to be so credited shall be specified by the Committee and set forth in the Award Agreement. Such additional Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Stock Units originally subject to the Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, appropriate adjustments shall be made in the Participant's Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award.

(ii) **Settlement of Stock Unit Awards.** A Participant electing to receive an Award of Stock Units pursuant to this Section 12, shall specify at the time of such election a settlement date with respect to such Award in accordance with rules established by the Committee. Except as otherwise set forth in the applicable Award Agreement, the Company shall issue to the Participant upon the earlier of the settlement date elected by the Participant or the date of the Participant's Separation from Service, a number of whole shares of Stock equal to the number of whole Stock Units subject to the Stock Unit Award. The Participant shall not be required to pay any additional consideration (other than applicable tax withholding) to acquire such shares. Any fractional Stock Unit subject to the Stock Unit Award shall be settled by the Company by payment in cash of an amount equal to the Fair Market Value as of the payment date of such fractional share.

13. **OTHER STOCK-BASED AWARDS** .

In addition to the Awards set forth in Sections 6 through 12 above, the Committee, in its sole discretion, may carry out the purpose of this Plan by awarding Stock-Based Awards as it determines to be in the best interests of the Company and subject to such other terms and conditions as it deems necessary and appropriate. Such awards may be evidenced by Award Agreements in such form as the Committee shall from time to time establish.

14. **CHANGE IN CONTROL .**

14.1 **Effect of Change in Control .** Except as set forth in an applicable Award Agreement, in the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Awards or substitute for such Awards substantially equivalent Awards covering the Acquiror's stock. Except as set forth in an applicable Award Agreement, any such Awards which are neither assumed, continued, or substituted by the Acquiror in connection with the Change in Control nor exercised (if applicable) as of the Change in Control shall, contingent on the Change in Control, become fully vested, and Options and SARs become exercisable immediately prior to the Change in Control. Except as set forth in an applicable Award Agreement, Awards which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting and/or exercisability, or lapse of restrictions in connection with the Participant's termination of Service in connection with the Change in Control as the Committee or Board may determine, if any.

14.2 **Non-employee Director Awards** . Notwithstanding the foregoing, Non-employee Director Awards shall be subject to the terms of Section 7, and not this Section 14.

15. **COMPLIANCE WITH SECURITIES LAW .**

The grant of Awards and the issuance of shares of Stock pursuant to any Award shall be subject to compliance with all applicable requirements of federal, state and foreign law with respect to such securities and the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, no Award

may be exercised or shares issued pursuant to an Award unless (a) a registration statement under the Securities Act shall at the time of such exercise or issuance be in effect with respect to the shares issuable pursuant to the Award or (b) in the opinion of legal counsel to the Company, the shares issuable pursuant to the Award may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares hereunder shall relieve the Company of any liability in respect of the failure to issue or sell such shares as to which such requisite authority shall not have been obtained. As a condition to issuance of any Stock, the Company may require the Participant to satisfy any qualifications that may be necessary or appropriate, to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect thereto as may be requested by the Company.

16. TAX WITHHOLDING .

16.1 **Tax Withholding in General.** The Company shall have the right to deduct from any and all payments made under the Plan, or to require the Participant, through payroll withholding, cash payment or otherwise, including by means of a Cashless Exercise or Net Exercise of an Option, to make adequate provision for, the federal, state, local and foreign taxes, if any, required by law to be withheld by the Participating Company Group with respect to an Award or the shares acquired pursuant thereto. The Company shall have no obligation to deliver shares of Stock, to release shares of Stock from an escrow established pursuant to an Award Agreement, or to make any payment in cash under the Plan unless the Participating Company Group's tax withholding obligations have been satisfied by the Participant.

16.2 **Withholding in Shares.** The Company shall have the right, but not the obligation, to deduct from the shares of Stock issuable to a Participant upon the exercise or settlement of an Award, or to accept from the Participant the tender of, a number of whole shares of Stock having a Fair Market Value, as determined by the Company, equal to all or any part of the tax withholding obligations of the Participating Company Group. Notwithstanding the foregoing, the Fair Market Value of any shares of Stock withheld or tendered to satisfy any such tax withholding obligations shall not exceed the amount determined by the applicable minimum statutory withholding rates to the extent required to avoid adverse accounting or other consequences to the Company or Participant.

17. AMENDMENT OR TERMINATION OF PLAN .

The Board or the Committee may amend, suspend or terminate the Plan at any time. However, without the approval of the Company's shareholders, there shall be (a) no increase in the maximum aggregate number of shares of Stock that may be issued under the Plan (except by operation of the provisions of Section 4.2), (b) no change in the class of persons eligible to receive Incentive Stock Options, (c) no amendment to Section 5.4(b) or 5.4(c), and (d) no other amendment of the Plan that would require approval of the Company's shareholders under any applicable law, regulation or rule. Notwithstanding the foregoing, only the Board may amend Section 7 and may do so without the approval of the Company's shareholders. No amendment, suspension or termination of the Plan shall affect any then outstanding Award unless expressly provided by the Board or the Committee. In any event, no amendment, suspension or termination of the Plan may adversely affect any then outstanding Award without the consent of the Participant unless necessary to comply with any applicable law, regulation or rule.

18. MISCELLANEOUS PROVISIONS .

18.1 **Repurchase Rights .** Shares issued under the Plan may be subject to one or more repurchase options, or other conditions and restrictions as determined by the Committee in its discretion at the time the Award is granted. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

18.2 **Provision of Information.** Each Participant shall be given access to information concerning the Company equivalent to that information generally made available to the Company's common shareholders.

18.3 **Rights as Employee, Consultant or Director.** No person, even though eligible pursuant to Section 5, shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant. Nothing in the Plan or any Award granted under the Plan shall confer on any Participant a right to remain an Employee, Consultant or Director or interfere with or limit in any way any right of a Participating Company to terminate the Participant's Service at any time. To the extent that an Employee of a Participating Company other than the Company receives an Award under the Plan, that Award shall in no event be understood or interpreted to mean that the Company is the Employee's employer or that the Employee has an employment relationship with the Company. A Participant's rights, if any, in respect of or in connection with any Award is derived solely from the discretionary decision of the Company to permit the individual to participate in the Plan and to benefit from a discretionary Award. By accepting an Award under the Plan, a Participant expressly acknowledges that there is no obligation on the part of the Company to continue the Plan and/or grant any additional Awards. Any Award granted hereunder is not intended to be compensation of a continuing or recurring nature, or part of a Participant's normal or expected compensation, and in no way represents any portion of a Participant's salary, compensation, or other remuneration for purposes of pension benefits, severance, redundancy, resignation or any other purpose. The Company and its Parent Corporations and Subsidiary Corporations and Affiliates reserve the right to terminate the Service of any person at any time, and for any reason, subject to applicable laws and such person's written employee agreement (if any), and such terminated person shall be deemed irrevocably to have waived any claim to damages or specific performance for breach of contract or dismissal, compensation for loss of office, tort or otherwise with respect to the Plan or any outstanding Award that is forfeited and/or is terminated by its terms or to any future Award.

18.4 **Rights as a Shareholder.** A Participant shall have no rights as a shareholder with respect to any shares covered by an Award until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). No adjustment shall be made for dividends, distributions or other rights for which the record date is prior to the date such shares are issued, except as provided in another provision of the Plan.

18.5 **Fractional Shares.** The Company shall not be required to issue fractional shares upon the exercise or settlement of any Award.

18.6 **Severability** . If any one or more of the provisions (or any part thereof) of this Plan shall be held invalid, illegal or unenforceable in any respect, such provision shall be modified so as to make it valid, legal and enforceable, and the validity, legality and enforceability of the remaining provisions (or any part thereof) of the Plan shall not in any way be affected or impaired thereby.

18.7 **Beneficiary Designation.** Subject to local laws and procedures, each Participant may file with the Company a written designation of a beneficiary who is to receive any benefit under the Plan to which the Participant is entitled in the event of such Participant's death before he or she receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. If a married Participant designates a beneficiary other than the Participant's spouse, the effectiveness of such designation may be subject to the consent of the Participant's spouse. If a Participant dies without an effective designation of a beneficiary who is living at the time of the Participant's death, the Company will pay any remaining unpaid benefits to the Participant's legal representative.

18.8 **Unfunded Obligation.** Participants shall have the status of general unsecured creditors of the Company. Any amounts payable to Participants pursuant to the Plan shall be unfunded and unsecured obligations for all purposes, including, without limitation, Title I of the Employee Retirement Income Security Act of 1974. No

Participating Company shall be required to segregate any monies from its general funds, or to create any trusts, or establish any special accounts with respect to such obligations. The Company shall retain at all times beneficial ownership of any investments, including trust investments, which the Company may make to fulfill its payment obligations hereunder. Any investments or the creation or maintenance of any trust or any Participant account shall not create or constitute a trust or fiduciary relationship between the Committee or any Participating Company and a Participant, or otherwise create any vested or beneficial interest in any Participant or the Participant's creditors in any assets of any Participating Company. The Participants shall have no claim against any Participating Company for any changes in the value of any assets which may be invested or reinvested by the Company with respect to the Plan. Each Participating Company shall be responsible for making benefit payments pursuant to the Plan on behalf of its Participants or for reimbursing the Company for the cost of such payments, as determined by the Company in its sole discretion. In the event the respective Participating Company fails to make such payment or reimbursement, a Participant's (or other individual's) sole recourse shall be against the respective Participating Company, and not against the Company. A Participant's acceptance of an Award pursuant to the Plan shall constitute agreement with this provision.

18.9 **Choice of Law.** Except to the extent governed by applicable federal law, the validity, interpretation, construction and performance of the Plan and each Award Agreement shall be governed by the laws of the State of California, without regard to its conflict of law rules.

18.10 **Section 409A of the Code.** Notwithstanding anything to the contrary in the Plan, to the extent (i) any Award payable in connection with a Participant's Separation from Service constitutes deferred compensation subject to (and not exempt from) Section 409A of the Code and (ii) the Participant is deemed at the time of such separation to be a "specified employee" under Section 409A of the Code and the Treasury regulations thereunder, then payment shall not be made or commence until the earlier of (i) six (6)-months after such Separation from Service or (ii) the date of the Participant's death following such Separation from Service; provided, however, that such delay shall only be effected to the extent required to avoid adverse tax treatment to the Participant, including (without limitation) the additional twenty percent (20%) tax for which the Participant would otherwise be liable under Section 409A(a)(1)(B) of the Code in the absence of such delay. Upon the expiration of the applicable delay period, any payment which would have otherwise been paid during that period (whether in a single sum or in installments) in the absence of this paragraph shall be paid to the Participant or the Participant's beneficiary in one lump sum on the first business day immediately following such delay and any undelayed payments will be paid in accordance with their normal terms.

18.11 **Restrictions on Transfer** . No Award and no shares of Stock that have not been issued or as to which any applicable restriction, performance or deferral period has not lapsed, may be sold, assigned, transferred, pledged or otherwise encumbered, other than by will or the laws of decent and distribution, and such Award may be exercised during the life of the Participant only by the Participant or the Participant's guardian or legal representative. Notwithstanding the foregoing, to the extent permitted by the Committee, in its discretion, and set forth in the applicable Award Agreement, an Award shall be assignable or transferrable to a "family member" or other permitted transferee to the extent covered under Form S-8 Registration Statement under the Securities Act.

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PLAN HISTORY AND NOTES TO COMPANY

| | |
|---|---|
| February 19, 2014 | Board adopts Plan with a reserve of 17 million shares, less one share for every one share of Stock covered by an award granted under the Prior Plan after December 31, 2013 and prior to the Effective Date. |
| May 12, 2014 | Shareholders approve Plan. Plan Effective Date |
| January 1, 2016 | The value of annual LTIP awards to non-employee directors increased to $140,000 from $105,000. |

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**EXHIBIT 12.1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2015** | **2014** | **2013** | **2012** | **2011** |
| **Earnings:** | | | | | |
| Net income | $ 862 | $ 1,433 | $ 866 | $ 811 | $ 845 |
| Income tax provision | (19) | 384 | 326 | 298 | 480 |
| Fixed charges | 1,260 | 1,176 | 971 | 891 | 880 |
| **Total earnings** | **$ 2,103** | **$ 2,993** | **$ 2,163** | **$ 2,000** | **$ 2,205** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 1,208 | $ 1,125 | $ 917 | $ 834 | $ 824 |
| Interest on capital leases | 4 | 6 | 7 | 9 | 16 |
| AFUDC debt | 48 | 45 | 47 | 48 | 40 |
| **Total fixed charges** | **$ 1,260** | **$ 1,176** | **$ 971** | **$ 891** | **$ 880** |
| **Ratios of earnings to fixed charges** | **1.67** | **2.55** | **2.23** | **2.24** | **2.51** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| **Earnings:** | | | | | |
| Net income | $ 862 | $ 1,433 | $ 866 | $ 811 | $ 845 |
| Income tax provision | (19) | 384 | 326 | 298 | 480 |
| Fixed charges | 1,260 | 1,176 | 971 | 891 | 880 |
| **Total earnings** | **$ 2,103** | **$ 2,993** | **$ 2,163** | **$ 2,000** | **$ 2,205** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 1,208 | $ 1,125 | $ 917 | $ 834 | $ 824 |
| Interest on capital leases | 4 | 6 | 7 | 9 | 16 |
| AFUDC debt | 48 | 45 | 47 | 48 | 40 |
| **Total fixed charges** | **$ 1,260** | **$ 1,176** | **$ 971** | **$ 891** | **$ 880** |
| **Preferred stock dividends:** | | | | | |
| Tax deductible dividends | $ 9 | $ 9 | $ 9 | $ 9 | $ 9 |
| Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements | 5 | 6 | 7 | 7 | 8 |
| **Total preferred stock dividends** | **14** | **15** | **16** | **16** | **17** |
| **Total combined fixed charges and preferred stock dividends** | **$ 1,274** | **$ 1,191** | **$ 987** | **$ 907** | **$ 897** |
| **Ratios of earnings to combined fixed charges and preferred stock dividends** | **1.65** | **2.51** | **2.19** | **2.21** | **2.46** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.3**
**PG&E CORPORATION**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2015** | **2014** | **2013** | **2012** | **2011** |
| **Earnings:** | | | | | |
| Net income | $ 888 | $ 1,450 | $ 828 | $ 830 | $ 858 |
| Income tax provision | (27) | 345 | 268 | 237 | 440 |
| Fixed charges | 1,284 | 1,206 | 1,012 | 931 | 919 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | (14) | (15) | (16) | (15) | (17) |
| **Total earnings** | **$ 2,131** | **$ 2,986** | **$ 2,092** | **$ 1,983** | **$ 2,200** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 1,218 | $ 1,140 | $ 942 | $ 859 | $ 846 |
| Interest on capital leases | 4 | 6 | 7 | 9 | 16 |
| AFUDC debt | 48 | 45 | 47 | 48 | 40 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated | 14 | 15 | 16 | 15 | 17 |
| **Total fixed charges** | **$ 1,284** | **$ 1,206** | **$ 1,012** | **$ 931** | **$ 919** |
| **Ratios of earnings to fixed charges** | **1.66** | **2.48** | **2.07** | **2.13** | **2.39** |

Note:
For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

**Significant Subsidiaries**

| Parent of Significant Subsidiary | Name of Significant Subsidiary | Jurisdiction of Formation of Subsidiary | Names under which Significant Subsidiary does business |
|---|---|---|---|
| PG&E Corporation | Pacific Gas and Electric Company | CA | Pacific Gas and Electric Company<br>PG&E |
| Pacific Gas and Electric Company | None | | |

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statements No. 333-193880 on Form S-3, 333-144498 on Form S-3D, and 333-129422, 333-176090, 333-195902 and 333-206457 on Form S-8 of PG&E Corporation and Registration Statement No. 333-193879 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 18, 2016 , relating to the consolidated financial statements of PG&E Corporation and subsidiaries ("the Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility"), the consolidated financial statement schedules of the Company and the Utility, and the effectiveness of the Company's and the Utility's internal control over financial reporting, appearing in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2015.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 18, 2016

**POWER OF ATTORNEY**

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2015 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 2nd day of February, 2016.

| | |
|---|---|
| /s/ LEWIS CHEW | /s/ RICHARD A. MESERVE |
| Lewis Chew | Richard A. Meserve |
| /s/ ANTHONY F. EARLEY, JR. | /s/ FORREST E. MILLER |
| Anthony F. Earley, Jr. | Forrest E. Miller |
| /s/ FRED J. FOWLER | /s/ ROSENDO G. PARRA |
| Fred J. Fowler | Rosendo G. Parra |
| /s/ MARYELLEN C. HERRINGER | /s/ BARBARA L. RAMBO |
| Maryellen C. Herringer | Barbara L. Rambo |
| /s/ RICHARD C. KELLY | /s/ ANNE SHEN SMITH |
| Richard C. Kelly | Anne Shen Smith |
| /s/ ROGER H. KIMMEL | /s/ BARRY LAWSON WILLIAMS |
| Roger H. Kimmel | Barry Lawson Williams |

**POWER OF ATTORNEY**

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2015 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 2nd day of February, 2016.

/s/ LEWIS CHEW
Lewis Chew

/s/ ANTHONY F. EARLEY, JR
Anthony F. Earley, Jr.

/s/ FRED J. FOWLER
Fred J. Fowler

/s/ MARYELLEN C. HERRINGER
Maryellen C. Herringer

/s/ RICHARD C. KELLY
Richard C. Kelly

/s/ ROGER H. KIMMEL
Roger H. Kimmel

/s/ RICHARD A. MESERVE
Richard A. Meserve

/s/ FORREST E. MILLER
Forrest E. Miller

/s/ ROSENDO G. PARRA
Rosendo G. Parra

/s/ BARBARA L. RAMBO
Barbara L. Rambo

/s/ ANNE SHEN SMITH
Anne Shen Smith

/s/ NICKOLAS STAVROPOULOS
Nickolas Stavropoulos

/s/ BARRY LAWSON WILLIAMS
Barry Lawson Williams

/s/ GEISHA J. WILLIAMS
Geisha J. Williams

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2015 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.
Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Jason P. Wells, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2015 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

JASON P. WELLS

Jason P. Wells
Senior Vice President and Chief Financial Officer

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Nickolas Stavropoulos, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2015 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

NICKOLAS STAVROPOULOS
Nickolas Stavropoulos
President, Gas

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Geisha J. Williams, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2015 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

GEISHA J. WILLIAMS
Geisha J. Williams
President, Electric

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Dinyar B. Mistry, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2015 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2016

DINYAR B. MISTRY
Dinyar B. Mistry
Vice President, Chief Financial Officer, and Controller

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2015 ("Form 10-K"), I, Anthony F. Earley, Jr., Chairman, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ANTHONY F. EARLEY, JR.

ANTHONY F. EARLEY, JR.
Chairman, Chief Executive Officer and President

February 18, 2016

# CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2015 ("Form 10-K"), I, Jason P. Wells, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

JASON P. WELLS

JASON P. WELLS
Senior Vice President and
Chief Financial Officer

February 18, 2016

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2015 ("Form 10-K"), I, Nickolas Stavropoulos, President, Gas of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

NICKOLAS STAVROPOULOS

NICKOLAS STAVROPOULOS
President, Gas

February 18, 2016

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2015 ("Form 10-K"), I, Geisha J. Williams, President, Electric of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

GEISHA J. WILLIAMS
GEISHA J. WILLIAMS
President, Electric

February 18, 2016

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2015 ("Form 10-K"), I, Dinyar B. Mistry, Vice President, Chief Financial Officer, and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

DINYAR B. MISTRY

DINYAR B. MISTRY
Vice President, Chief Financial Officer, and Controller

February 18, 2016

# Exhibit 5

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-K**

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the Fiscal Year Ended December 31, 2016**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from _________ to ___________**

| Commission File Number | Exact Name of Registrant as Specified In Its Charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each class | Name of each exchange on which registered |
|---|---|
| **PG&E Corporation:** Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company:** First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE MKT LLC |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2016, the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $31,807 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |

**Common Stock outstanding as of February 7, 2017:**

| | |
|---|---|
| PG&E Corporation: | 507,782,249 shares |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

| | |
|---|---|
| Designated portions of the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |

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*UNITS OF MEASUREMENT*

| | | |
|---|---|---|
| 1 Kilowatt (kW) | = | One thousand watts |
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt (GW) | = | One million kilowatts |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |
| 1 Bcf | = | One billion cubic feet |
| 1 MDth | = | One thousand decatherms |

## *GLOSSARY*

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2016 Form 10-K | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2016 |
| AB | Assembly Bill |
| AFUDC | allowance for funds used during construction |
| ALJ | administrative law judge |
| ARO | asset retirement obligation |
| ASU | accounting standard update issued by the FASB (see below) |
| CAISO | California Independent System Operator |
| Cal Fire | California Department of Forestry and Fire Protection |
| CARB | California Air Resources Board |
| CCA | Community Choice Aggregator |
| Central Coast Board | Central Coast Regional Water Quality Control Board |
| CEC | California Energy Resources Conservation and Development Commission |
| $CO_2$ | carbon dioxide |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DER | distributed energy resources |
| Diablo Canyon | Diablo Canyon nuclear power plant |
| DOE | U.S. Department of Energy |
| DOGGR | Division of Oil, Gas and Geothermal Resources |
| DOI | U.S. Department of the Interior |
| DTSC | Department of Toxic Substances Control |
| EMANI | European Mutual Association for Nuclear Insurance |
| EPA | Environmental Protection Agency |
| EPS | earnings per common share |
| EV | electric vehicle |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| IOUs | investor-owned utility(ies) |
| IRS | Internal Revenue Service |
| LTIP | long-term incentive plan |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K |
| MOU | memorandum of understanding |
| NAV | net asset value |
| NDTCP | Nuclear Decommissioning Cost Triennial Proceedings |
| NEIL | Nuclear Electric Insurance Limited |
| NEM | net energy metering |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| OII | order instituting investigation |
| ORA | Office of Ratepayer Advocates |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PSEP | pipeline safety enhancement plan |
| QF | qualifying facility |
| Regional Board | California Regional Water Quality Control Board, Lahontan Region |

| | |
|---|---|
| REITS | real estate investment trust |
| RFO | requests for offers |
| ROE | return on equity |
| RPS | renewable portfolio standard |
| SB | Senate Bill |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC |
| TE | transportation electrification |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |
| Water Board | California State Water Resources Control Board |

## PART I

### ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found below in Item 6. Selected Financial Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

At December 31, 2016, PG&E Corporation and the Utility had approximately 24,000 regular employees, approximately 30 of which were employees of PG&E Corporation. Of the Utility's regular employees, approximately 14,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW"); the Engineers and Scientists of California ("ESC"); and the Service Employees International Union ("SEIU"). A new SEIU collective bargaining agreement was ratified in December 2016 and is effective August 1, 2016 through December 31, 2019. Two new agreements (Physical and Clerical) with IBEW and an agreement with ESC were ratified in 2016 and were retroactive to January 1, 2016. They will expire on December 31, 2019.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, *www.pgecorp.com*, and the Utility's website, *www.pge.com*, as promptly as practicable after they are filed with, or furnished to, the SEC. Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's regulatory proceedings before the CPUC and the FERC at *http:// investor.pgecorp.com*, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on these websites is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC.

This Annual Report on Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see "Item 1A. Risk Factors" and the section entitled "Forward-Looking Statements" in MD&A.

### Regulatory Environment

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is subject to the jurisdiction of the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies with respect to safety, the environment, and health. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility.

PG&E Corporation is a "public utility holding company" as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

*The California Public Utilities Commission*

The CPUC is a regulatory agency that regulates privately owned public utilities in California. The CPUC consists of five commissioners appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electric and natural gas distribution operations, electric generation, and natural gas transmission and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $50,000 per day, per violation, for violations that occurred after January 1, 2012. (The statutory maximum penalty for violations that occurred before January 1, 2012 is $20,000 per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. In September 2016, the CPUC adopted improvements and refinements to its gas and electric safety citation programs. Specifically, the final decision refines the criteria for the SED to use in determining whether to issue a citation and the amount of penalty, sets an administrative limit of $8 million per citation issued, makes self-reporting voluntary in both gas and electric programs, adopts detailed criteria for the utilities to use to voluntarily self-report a potential violation, and refines other issues in the programs. The decision also merges the rules applicable to its gas and electric safety citation programs into a single set of rules that replaces the previous safety citation programs.

The California State Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to increasing renewable energy resources, the development and widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, the establishment of energy storage procurement targets, and the development of a state-wide electric vehicle charging infrastructure. The CPUC is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs. The CPUC also conducts audits and reviews of the Utility’s accounting, performance, and compliance with regulatory guidelines.

The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation’s Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see “Liquidity and Financial Resources” in MD&A and Item 1A. Risk Factors.)

*The Federal Energy Regulatory Commission and the California Independent System Operator*

The FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility’s transmission systems with other electric system and generation facilities, the tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation’s electric transmission grid, including standards to protect the nation’s bulk power system against potential disruptions from cyber and physical security breaches. The FERC has authority to impose fines of up to $1 million per day for violations of certain federal statutes and regulations.

The CAISO is the FERC-approved regional transmission organization for the Utility’s service territory. The CAISO controls the operation of the electric transmission system in California and provides open access transmission service on a non-discriminatory basis. The CAISO also is responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generating capacity, and ensuring that the reliability of the transmission system is maintained.

*The Nuclear Regulatory Commission*

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electricity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. (For more information about Diablo Canyon, see "Regulatory Matters – Diablo Canyon Nuclear Power Plant" in MD&A and Item 1A. Risk Factors below.)

***Other Regulators***

The CEC is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans and for adopting building and appliance energy efficiency requirements.

The CARB is the state agency responsible for setting and monitoring GHG and other emission limits. The CARB is also responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California. (See "Environmental Regulation - Air Quality and Climate Change" below.)

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and highways. In exchange for the right to use public streets and highways, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date.

**Ratemaking Mechanisms**

The Utility's rates for electricity and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service including a return on invested capital ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administration and general expenses) and capital costs (e.g., depreciation, tax, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in MD&A), including its costs to procure electricity, natural gas and nuclear fuel, to administer public purpose and customer programs, and to decommission its nuclear facilities.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. The authorized rate of return on all other Utility assets is set in the CPUC's cost of capital proceeding. Other than its electric transmission and certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume. Regulatory balancing accounts, or revenue adjustment mechanisms, ensure that the Utility will fully collect its authorized base revenue requirements. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in MD&A) within its authorized base revenue requirements.

Both electric and gas rates vary depending on seasons mostly due to the influence of weather. Electricity rates increase during the summer months (May – October) because of higher demand, driven by air conditioning loads, while gas service rates generally increase during the winter months (November – March) to account for the gas peak due to heating.

During 2016, the CPUC continued to implement state law requirements to reform residential electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. (See "Legislative and Regulatory Initiatives" in MD&A for more information on specific CPUC proceedings.)

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn some additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs. (See "Regulatory Matters – 2014 – 2015 Energy Efficiency Incentive Awards" in MD&A.)

***Base Revenues***

*General Rate Cases*

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs, including return on rate base, related to its electricity distribution, natural gas distribution, and Utility owned electricity generation operations. The CPUC generally conducts a GRC every three or four years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). Attrition year rate adjustments are generally provided for cost increases related to increases in invested capital and inflation. Parties in the Utility's GRC include the ORA and TURN, who generally represent the overall interests of residential customers, as well as a myriad of other intervenors who represent other business, community, customer, environmental, and union interests. (For more information about the Utility's current GRC proceeding, see "Regulatory Matters −2017 General Rate Case" in MD&A.)

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in the GT&S rate case. The CPUC generally conducts a GT&S rate case every three or four years. Similar to the GRC proceeding, the CPUC approves the annual revenue requirements for the first year (or "test year") of the GT&S period and typically determines annual increases in revenue requirements for attrition years of the GT&S period. Parties in the Utility's GT&S rate case include the ORA and TURN, who generally represent the overall interests of residential customers, as well as other intervenors who represent other business, community, customer, and union interests. (For more information, see "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" in MD&A.)

*Cost of Capital Proceedings*

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2017, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also set the authorized ROE through 2017 at 10.40%. The CPUC adopted an adjustment mechanism to allow the Utility's capital structure and ROE to be adjusted if the utility bond index changes by certain thresholds on an annual basis. On February 25, 2016, the CPUC issued a decision granting a petition for modification filed by the Utility and the other California IOUs to clarify that the CPUC's previously adopted cost of capital adjustment mechanism would not be triggered for 2017.

On February 6, 2017, the Utility and other California IOUs entered into a MOU with the CPUC, ORA, and TURN to extend the next cost of capital application filing deadline two years to April 22, 2019 for the year 2020. To implement the MOU, on February 7, 2016, the IOUs, ORA, and TURN filed with the CPUC a petition for modification of prior CPUC decisions addressing cost of capital. If the petition for modification is approved as submitted it would reduce the Utility's ROE from 10.40% to 10.25% and reset the Utility's authorized cost of long-term debt and preferred stock beginning January 1, 2018. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity would remain unchanged. The Utility's cost of capital adjustment mechanism would not operate in 2017 but could operate in 2018 to change the cost of capital for 2019. If the mechanism is activated for 2019, the Utility's cost of capital, including its new ROE of 10.25%, will be adjusted according to the existing terms of the mechanism. Concurrently with the petition for modification, the Utility and other California IOUs also sent a letter to the executive director of the CPUC requesting that the existing April 2017 filing due date for the 2018 cost of capital be deferred while the CPUC is considering the petition for modification. On February 13, 2017, the executive director of the CPUC granted the request. As extended, the Utility and the other California IOUs would file their next cost of capital applications 60 days after the effective date of the CPUC decision on the petition for modification, or April 20, 2017, whichever is later, if the CPUC does not grant the petition for modification.

The Utility expects that the CPUC may issue a decision in the first half of 2017. (For more information, see "Regulatory Matters – CPUC Cost of Capital" in MD&A.)

*Electricity Transmission Owner Rate Cases*

The FERC determines the amount of authorized revenue requirements, including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The Utility generally files a TO rate case every year. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. These FERC-approved rates are included: 1) by the CPUC in the Utility's retail electric rates and are collected from retail electric customers; and 2) by the CAISO in its Transmission Access Charges to wholesale customers. (For more information, see "Regulatory Matters – FERC Transmission Owner Rate Cases" in MD&A.) The Utility also recovers a portion of its revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are charged individualized rates based on the terms of their contracts.

***Revenues to Recover Energy Procurement and Other Pass-Through Costs***

*Electricity Procurement Costs*

California investor-owned electric utilities are responsible for procuring electrical capacity required to meet bundled customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electricity contracts. The utilities are responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their bundled customer procurement plans based on long-term demand forecasts. The Utility's most recent bundled customer procurement plan was approved in October 2015, and will remain in effect until the plan is superseded by a subsequent CPUC-approved plan.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved bundled customer procurement plans without further after-the-fact reasonableness review by the CPUC. The CPUC may disallow costs associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to follow the principles of least-cost dispatch. Additionally, the cost of replacement power procured due to unplanned outages at Utility owned generation facilities may be disallowed.

The Utility recovers its electricity procurement costs annually primarily through the energy resource recovery account. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.) Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electricity rates more frequently if the forecasted aggregate over-collections or under-collections in the energy resource recovery account exceed 5% of its prior year electricity procurement and utility-owned generation revenues. The CPUC performs an annual compliance review of the transactions recorded in the energy resource recovery account.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, to meet mandatory renewable energy targets, and to comply with resource adequacy requirements. (For more information, see "Electric Utility Operations – Electricity Resources" below as well as Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

*Natural Gas Procurement, Storage, and Transportation Costs*

The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electricity rates.

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as "core" customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments for its core gas portfolio, through its retail gas rates, subject to limits as set forth in its core procurement incentive mechanism described below. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rate changes.

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs for its core gas portfolio. Under the core procurement incentive mechanism, the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of these savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by FERC-approved tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. The FERC approves the United States tariffs that shippers, including the Utility, pay for pipeline service, and the applicable Canadian tariffs are approved by the National Energy Board, a Canadian regulatory agency. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as a cost of electricity.

*Costs Associated with Public Purpose and Customer Programs*

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide a discount rate for low-income customers, known as California Alternate Rates for Energy ("CARE"), which is subsidized by the Utility's other customers.

*Nuclear Decommissioning Costs*

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Nuclear decommissioning costs are collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approval of the Utility's updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility's nuclear plants.

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025. (For more information, see "Legislative and Regulatory Initiatives" in MD&A.)

**Electric Utility Operations**

The Utility generates electricity and provides electricity transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides "bundled" services (i.e., electricity, transmission and distribution services) to most customers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations.

The Utility has continued to invest in its vision for a future electric grid which will allow customers to choose new, advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. In addition, in December 2016, the CPUC issued a final decision establishing a three-year EV program for the Utility to deploy up to 7,500 charging stations. (For more information, see "Legislative and Regulatory Initiatives" in MD&A.)

*Electricity Resources*

The Utility is required to maintain generating capacity adequate to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule all of the electricity resources within its portfolio in the most cost-effective way.

The following table shows the percentage of the Utility's total deliveries of electricity to customers in 2016 represented by each major electricity resource, and further discussed below.

Total 2016 Actual Electricity Generated and Procured – 68,441 GWh [(1)]:

| | Percent of Bundled Retail Sales | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 24.2 % | |
| Small Hydroelectric | 1.3 % | |
| Large Hydroelectric | 9.8 % | |
| Fossil fuel-fired | 7.3 % | |
| Solar | 0.5 % | |
| Total | | 43.1 % |
| | | |
| Qualifying Facilities | | |
| Renewable | 2.6 % | |
| Non-Renewable | 5.1 % | |
| Total | | 7.7 % |
| Irrigation Districts and Water Agencies | | |
| Large Hydroelectric | 0.5 % | |
| Total | | 0.5 % |
| Other Third-Party Purchase Agreements | | |
| Renewable | 28.4 % | |
| Large Hydroelectric | 2.1 % | |
| Non-Renewable | 4.8 % | |
| Total | | 35.3 % |
| Others, Net [(2)] | | 13.4 % |
| **Total [(3)]** | | **100 %** |

[(1)] This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
[(2)] Mainly comprised of net CAISO open market purchases.
[(3)] Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by transmission and distribution related system losses.

*Renewable Energy Resources.* California law established an RPS that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers. In October 2015, the California Governor signed SB 350, the Clean Energy and Pollution Reduction Act of 2015 into law. SB 350 became effective January 1, 2016, and increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period, and in each three-year compliance period thereafter, unless changed by legislative action. SB 350 provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable from customers as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher renewable targets.

As indicated below, the Utility's application and joint proposal to retire Diablo Canyon include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables. (For more information, see "Legislative and Regulatory Initiatives" in MD&A.)

Renewable generation resources, for purposes of the RPS requirements, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. During 2016, 32.8% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 28.4% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (2.6%), the Utility's small hydroelectric facilities (1.3%), and the Utility's solar facilities (0.5%).

The total 2016 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales |
|---|---|---|
| Biopower | 2,958 | 4.3% |
| Geothermal | 3,705 | 5.4% |
| Small Hydroelectric | 1,800 | 2.6% |
| Solar | 8,598 | 12.6% |
| Wind | 5,419 | 7.9% |
| **Total** | **22,480** | **32.8%** |

*Energy Storage.* As required by California law, the CPUC has opened a proceeding to establish a multi-year energy storage procurement framework, including energy storage procurement targets to be achieved by each load-serving entity under the CPUC jurisdiction, including the Utility. Under the adopted energy storage procurement framework, the Utility is required to procure 580 MW of qualifying storage capacity by 2020, with all energy storage projects required to be operational by the end of 2024.

The CPUC also adopted biennial interim storage targets for the Utility, beginning in 2014 and ending in 2020. Under the adopted framework, the Utility is required to conduct biennial competitive RFOs to help meet its interim storage targets.

The Utility conducted an RFO in 2014. The Utility's 2014 energy storage target was 90 MW, some of which the Utility met through already existing projects, or projects anticipated to result from other CPUC proceedings. As a result of the 2014 RFO, 70 MW of transmission and distribution contracts have been approved by the CPUC. Contracts for 6MW were rejected by the CPUC, including a behind-the-meter project. Additionally, contracts for 13 MW were withdrawn by the Utility.

The Utility's 2016 energy storage target is 120 MW. On November 30, 2016, the Utility issued its 2016 RFO. The Utility must submit all executed contracts from the 2016 RFO to the CPUC for approval by December 1, 2017. The Utility expects to increase the amount of storage it is attempting to procure in its 2016 RFO by the shortfall from the 2014 target.

*Owned Generation Facilities.* At December 31, 2016, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---|---|---|---|
| Nuclear [(1)]: | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric [(2)]: | | | |
| Conventional | 16 counties in northern and central California | 104 | 2,684 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| Fuel Cell: | | | |
| CSU East Bay Fuel Cell | Alameda | 1 | 1 |
| SF State Fuel Cell | San Francisco | 2 | 2 |
| Photovoltaic [(3)]: | Various | 13 | 152 |
| **Total** | | **137** | **7,691** |

[(1)] The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses expire in 2024 and 2025, respectively. (See "Diablo Canyon Nuclear Power Plant" in. MD&A and Item 1A. Risk Factors.)
[(2)] The Utility's hydroelectric system consists of 107 generating units at 67 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years.
[(3)] The Utility's large photovoltaic facilities are Five Points solar station (15 MW), Westside solar station (15 MW), Stroud solar station (20 MW), Huron solar station (20 MW), Cantua solar station (20 MW), Giffen solar station (10 MW), Gates solar station (20 MW), West Gates solar station (10 MW) and Guernsey solar station (20 MW). All of these facilities are located in Fresno County, except for Guernsey solar station, which is located in Kings County.

*Generation Resources from Third Parties.* The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. (See "Ratemaking Mechanisms" above.) For more information regarding the Utility's power purchase agreements, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

***Electricity Transmission***

At December 31, 2016, the Utility owned approximately 18,400 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 92 electric transmission substations with a capacity of approximately 64,600 MVA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes many western states, Alberta and British Columbia, and parts of Mexico.

In 2013, the Utility, MidAmerican Transmission, LLC, and Citizens Energy Corporation were selected by the CAISO to jointly develop a new 230-kV transmission line to address the growing power demand in the Fresno, Madera and Kings counties area. The CAISO has stated that the 2022 in-service date for the 70-mile line has been postponed, and has placed the project on hold. The Utility has stopped all work on the project pending a decision from the CAISO that could defer or cancel the project. A decision by the CAISO is expected by March 2018. In addition, as a part of the CAISO's 2016-2017 planning efforts, the CAISO conducted a review of a number of local area low voltage transmission projects in the Utility's service territory that were predominantly load forecast driven. As a result of the review, the CAISO found that a number of lower-voltage transmission projects were no longer required and recommended cancelling or requiring further review in the 2017-2018 planning cycle.

On March 29, 2016, the Utility entered into an agreement with TransCanyon, LLC, a joint venture between subsidiaries of Berkshire Hathaway Energy and Pinnacle West Capital Corporation, to jointly pursue competitive transmission opportunities solicited by the CAISO. The Utility and TransCanyon intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

Throughout 2016, the Utility upgraded several critical substations and re-conductored a number of transmission lines to improve maintenance and system flexibility, reliability and safety. The Utility expects to undertake various additional transmission projects over the next several years to upgrade and expand the capacity of its transmission system to secure access to renewable generation resources and replace aging or obsolete equipment and improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment.

***Electricity Distribution***

The Utility's electricity distribution network consists of approximately 142,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 59 transmission switching substations, and 606 distribution substations, with a capacity of approximately 31,800 MVA. The Utility’s distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility’s customers.

These distribution substations serve as the central hubs for the Utility’s electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. In 2016 the Utility commenced operations in a new electric distribution control center facility in Concord, California; along with the existing distribution control centers in Rocklin and Fresno, California, these control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2016, the Utility continued to deploy its Fault Location, Isolation, and Service Restoration circuit technology which involves the rapid operation of smart switches to reduce the duration of customer outages. Another 89 circuits were outfitted with this equipment, bringing the total deployment to 789 of the Utility’s 3,200 distribution circuits. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2017.

### *Electricity Operating Statistics*

The following table shows certain of the Utility's operating statistics from 2014 to 2016 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 2016, 2015 and 2014.

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Customers (average for the year) | 5,349,691 | 5,311,178 | 5,276,025 |
| Deliveries (in GWh) [(1)] | 83,017 | 85,860 | 86,303 |
| Revenues (in millions): | | | |
| Residential | $ 5,409 | $ 5,032 | $ 4,784 |
| Commercial | 5,396 | 5,278 | 5,141 |
| Industrial | 1,525 | 1,555 | 1,543 |
| Agricultural | 1,226 | 1,233 | 1,172 |
| Public street and highway lighting | 80 | 83 | 79 |
| Other [(2)] | (68) | (84) | (172) |
| Subtotal | 13,568 | 13,097 | 12,547 |
| Regulatory balancing accounts [(3)] | 297 | 560 | 1,109 |
| **Total operating revenues** | **$ 13,865** | **$ 13,657** | **$ 13,656** |
| Selected Statistics: | | | |
| Average annual residential usage (kWh) | 6,115 | 6,294 | 6,458 |
| Average billed revenues per kWh: | | | |
| Residential | $ 0.1887 | $ 0.1719 | $ 0.1603 |
| Commercial | 0.1716 | 0.1640 | 0.1585 |
| Industrial | 0.0990 | 0.0973 | 0.0998 |
| Agricultural | 0.1814 | 0.1610 | 0.1516 |
| Net plant investment per customer | $ 7,195 | $ 6,660 | $ 6,339 |

(1) These amounts include electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
(2) This activity is primarily related to a remittance of revenue to the Department of Water Resources ("DWR") (the Utility acts as a billing and collection agent on behalf of the DWR), partially offset by other miscellaneous revenue items.
(3) These amounts represent revenues authorized to be billed.

### Natural Gas Utility Operations

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e., natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as core transport agents). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more than 90% of core customers, representing nearly 78% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers (i.e., outside of the Utility's service territory) and to third-party natural gas storage customers.

*Natural Gas Supplies*

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility can also receive natural gas from fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated generally based on market conditions. During 2016, the Utility purchased approximately 307,100 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all of this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 14% of the total natural gas volume the Utility purchased during 2016.

*Natural Gas System Assets*

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 2016, the Utility's natural gas system consisted of approximately 42,800 miles of distribution pipelines, over 6,700 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport natural gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border. Similarly, the Utility has firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport natural gas from supply points in the Southwestern United States to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas system in the area of Daggett, California. (For more information regarding the Utility's natural gas transportation agreements, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's transmission system. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later withdrawal. In addition, four independent storage operators are interconnected to the Utility's northern California transmission system.

As of December 31, 2016 the Utility had installed 268 automatic and remote control shut-off valves on its gas transmission system, as specified in the eleventh of twelve safety recommendations made by the NTSB following its investigation of the San Bruno accident. The NTSB closed that recommendation in 2015. The final safety recommendation, considered open and acceptable by the NTSB, involves ensuring that all high consequence pipeline mileage in the Utility's gas transmission system has been hydrostatically tested. As of December 31, 2016, the Utility has hydrostatically tested about 840 miles and completed the majority of this safety recommendation. The Utility currently plans to complete the NTSB recommendation by 2022 for the remaining approximately 28 aggregate pipeline miles (involving hundreds of primarily short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines).

In addition, in 2016, the Utility inspected 260 miles of transmission pipeline using in-line inspection tools and upgraded an additional 107 miles of transmission pipeline to allow for the use in-line inspection tools, replaced 127 miles of distribution main, and completed the installation of over 25,000 line makers to more easily identify the locations of gas pipelines.

*Natural Gas Operating Statistics*

The following table shows the Utility's operating statistics from 2014 through 2016 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 2016, 2015 and 2014.

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Customers (average for the year) | 4,442,379 | 4,415,332 | 4,394,283 |
| Gas purchased (MMcf) | 208,260 | 209,194 | 202,215 |
| Average price of natural gas purchased | $ 1.83 | $ 2.11 | $ 4.09 |
| Bundled gas sales (MMcf): | | | |
| Residential | 149,483 | 144,885 | 143,514 |
| Commercial | 46,507 | 43,888 | 42,080 |
| **Total Bundled Gas Sales** | **195,990** | **188,773** | **185,594** |
| Revenues (in millions): | | | |
| Bundled gas sales: | | | |
| Residential | $ 1,968 | $ 1,816 | $ 1,683 |
| Commercial | 439 | 403 | 419 |
| Other | 149 | 125 | 51 |
| Bundled gas revenues | 2,556 | 2,344 | 2,153 |
| Transportation service only revenue | 800 | 649 | 662 |
| Subtotal | 3,356 | 2,993 | 2,815 |
| Regulatory balancing accounts | 446 | 183 | 617 |
| **Total operating revenues** | **$ 3,802** | **$ 3,176** | **$ 3,432** |
| Selected Statistics: | | | |
| Average annual residential usage (Mcf) | 36 | 35 | 34 |
| Average billed bundled gas sales revenues per Mcf: | | | |
| Residential | $ 13.10 | $ 12.53 | $ 11.72 |
| Commercial | 9.45 | 9.18 | 9.96 |
| Net plant investment per customer | $ 2,808 | $ 2,573 | $ 2,468 |

**Competition**

***Competition in the Electricity Industry***

California law allows qualifying non-residential electric customers of investor-owned electric utilities to purchase electricity from energy service providers rather than from the utilities up to certain annual and overall GWh limits that have been specified for each utility. This arrangement is known as "direct access." In addition, California law permits cities, counties, and certain other public agencies that have qualified to become a CCA to generate and/or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents and businesses which do not affirmatively elect to continue to receive electricity from a utility.

The Utility continues to provide transmission, distribution, metering, and billing services to direct access customers, although these customers can choose to obtain metering and billing services from their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Utility is able to collect charges intended to recover the generation-related costs that the Utility incurred on behalf of direct access and CCA customers while they were the Utility's customers. The Utility remains the electricity provider of last resort for these customers.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, may seek to acquire the Utility's distribution facilities, generally through eminent domain. These same entities may, and sometimes do, construct duplicate distribution facilities to serve existing or new Utility customers.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-

generating customers to receive bill credits at the full retail rate, are increasing. These factors result in a shift of cost responsibility for grid and related services to other customers of the Utility.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission facilities within, or interconnected to, its service territory through a competitive bidding process managed by the CAISO.

***Competition in the Natural Gas Industry***

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

**Environmental Regulation**

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of $CO_2$ and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. (See Item 1A. Risk Factors.) Generally, the Utility recovers most of the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a ratemaking mechanism described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

***Hazardous Waste Compliance and Remediation***

The Utility's facilities are subject to various regulations adopted by the U.S. Environmental Protection Agency, including the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended. The Utility is also subject to the regulations adopted by other federal agencies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act, these persons (known as "potentially responsible parties") may be jointly and severally liable for the costs of cleaning up the hazardous substances, monitoring and paying for the harm caused to natural resources, and paying for the costs of health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the California Department of Toxic Substances Control, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

*Air Quality and Climate Change*

The Utility's electricity generation plants, natural gas pipeline operations, fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, $CO_2$, sulfur dioxide ($SO_2$), mono-nitrogen oxide ($NO_x$), particulate matter, and other GHG emissions.

In December 2009, the EPA concluded that GHG emissions contribute to climate change and issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. In May 2014, the U.S. Global Change Research Program (a confederation of the research arms of thirteen federal departments and agencies) released its third National Climate Assessment, which stated that the global climate is changing and that impacts related to climate change are already evident in many sectors and are expected to become increasingly disruptive across the nation throughout this century and beyond.

*Federal Regulation*. At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

In August 2015, the EPA published final regulations under section 111(b) of the Clean Air Act to control $CO_2$ emissions from new fossil fuel-fired power plants. While these regulations do not affect the Utility's existing power plants, the regulations impose emission limitations on fossil fuel-fired power plants constructed after January 8, 2014 and will affect the design, construction, operation and cost of such power plants.

In August 2015, the EPA also published final regulations under section 111(d) of the Clean Air Act to control $CO_2$ emissions from existing fossil fuel-fired power plants. These regulations are designed to reduce power plant $CO_2$ emissions on a national basis by as much as 32% by 2030, compared with 2005 levels. States were required to submit final plans to comply with these regulations by September 2016, but were permitted to request an extension to file such plans until September 2018. It is uncertain whether and how these federal regulations will ultimately impact California, since existing state regulation currently requires, among other things, the gradual reduction of state-wide GHG emissions to 40% below 1990 levels by 2030. Following publication of the EPA's regulations, in October 2015 West Virginia and several other states and parties challenged the EPA's section 111(d) regulations in the United States Court of Appeals for the District of Columbia Circuit and petitioned the Court to stay the regulations pending review of the appeal on the merits. The D.C. Circuit denied the request for stay but in February 2016, the United States Supreme Court granted a stay of the section 111(d) regulations pending review of the appeal by the D.C. Circuit. The Supreme Court's decision may affect the nature, extent and timing of implementation of these regulations. As described below, the Utility expects all costs and revenues associated with the state-wide, comprehensive cap-and-trade program to be passed through to customers.

With the change in federal administration from President Barack Obama to President Donald Trump, there is significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. The new administration has indicated that it intends to revoke the Clean Power Plan regulations and possibly withdraw from international efforts to combat climate change. Upon taking office, President Trump issued an executive order to freeze all regulations issued in the 60 days preceding his inauguration and directed the EPA and the White House to remove climate change-related materials and web pages, pending further review. It is assumed that the new administration also will take action to suspend all climate related regulatory and funding activities. In light of the potential policy reversal at the federal level, the State of California has indicated that it intends to continue and enhance its leadership on climate change nationally and globally.

*State Regulation.* California's AB 32, the Global Warming Solutions Act of 2006, provides for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target, including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy. The cap-and-trade program's first compliance period, which began on January 1, 2013, applied to the electricity generation and large industrial sectors. The next compliance period, which began on January 1, 2015, expanded to include the natural gas and transportation sectors, effectively covering all the economy's major sectors until 2020. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Emitters may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owners, and farmers) that occur outside of the emitters' facilities through CARB-qualified offset projects such as reforestation or biomass projects. Additionally, Senate Bill 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. CARB is currently considering regulatory amendments to the cap-and-trade program to extend the program's authority to 2030. The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers. The California RPS program that requires the utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California.

*Climate Change Mitigation and Adaptation Strategies.* During 2016, the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to plan for the actions that it will need to take to adapt to the likely impacts of climate change on the Utility's future operations, including forming an officer-level coordinating committee to govern and oversee the Utility's activities. The Utility regularly reviews the most relevant scientific literature on climate change such as sea level rise, temperature changes, rainfall and runoff patterns, and wildfire risk, to help the Utility identify and evaluate climate change-related risks and develop the necessary adaptation strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including extreme storms, heat waves and wildfires and uses its risk-assessment process to prioritize infrastructure investments for longer-term risks associated with climate change. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme, persistent, and frequent hot weather. The Utility believes its strategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage are effective strategies for adapting to the expected changes in demand for electricity. The Utility is making substantial investments to build a more modern and resilient system that can better withstand extreme weather and related emergencies. The Utility's vegetation management activities also reduce the risk of wildfire impacts on electric and gas facilities. Over the long-term, the Utility also faces the risk of higher flooding and inundation potential at coastal and low elevation facilities due to sea level rise combined with high tides, storm runoff and storm surges.

Notwithstanding the current high snowpack, climate scientists predict that climate change will result in varying temperatures and levels of precipitation in the Utility's service territory. This could, in turn, affect the Utility's hydroelectric generation. To plan for this potential change, the Utility is engaging with state and local stakeholders and is also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and collaborating on research and new modeling tools.

With respect to natural gas operations, both safety-related pipeline strength testing and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and volume of natural gas within pipelines prior to venting. In addition, the Utility continues to achieve reductions in methane emissions by implementing improvements in leak detection and repair, upgrades at metering and regulating stations, and maintenance and replacement of other pipeline materials.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2015 totaled more than 54 million metric tonnes of $CO_2$ equivalent, two-thirds of which came from customer natural gas use. The following table shows the 2015 GHG emissions data the Utility reported to the CARB under AB 32. PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| Source | Amount (metric tonnes $CO_2$ equivalent) |
|---|---:|
| Fossil Fuel-Fired Plants (1) | 2,875,176 |
| Natural Gas Compressor Stations and Storage Facilities (2) | 362,472 |
| Distribution Fugitive Natural Gas Emissions | 676,458 |
| Customer Natural Gas Use (3) | 43,022,557 |

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations.
(2) Including, but not limited to, compressor stations and storage facilities emitting more than 25,000 metric tonnes of $CO_2$ equivalent annually.
(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural gas local distribution companies. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities, as calculated by the CARB.

The following table shows the Utility's third-party-verified $CO_2$ emissions rate associated with the electricity delivered to customers in 2015 as compared to the national average for electric utilities:

| | Amount (pounds of $CO_2$ per MWh) |
|---|---:|
| U.S. Average (1) | 1,143 |
| Pacific Gas and Electric Company (2) | 405 |

(1) Source: EPA eGRID.
(2) Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's emissions rate.

***Air Emissions Data for Utility-Owned Generation***

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised approximately 40% of the Utility's delivered electricity in 2015. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | 2015 | 2014 |
|---|---:|---:|
| Total NOx Emissions (tons) | 160 | 141 |
| NOx Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total $SO_2$ Emissions (tons) | 17 | 14 |
| $SO_2$ Emissions Rate (pounds/MWh) | 0.0011 | 0.0010 |

***Water Quality***

On May 19, 2014, the EPA issued final regulations to implement the requirements of the federal Clean Water Act that require cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. Various industry and environmental groups have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Fourth Circuit. California's once-through cooling policy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, in 2010, the California Water Board adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The policy also provided for an alternative compliance approach for nuclear plants if certain criteria were met. As required by the policy, the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014. The report addressed feasibility, costs and timeframes to install alternative technologies at Diablo Canyon, such as cooling towers. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025, and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. Beginning in 2017, as required under the policy, the Utility will pay an annual interim mitigation fee until operations cease in 2024 and 2025.

Additionally, the Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Water Board and the California Attorney General's Office regarding the thermal component of the plant's once-through cooling discharge. (For more information, see "Diablo Canyon Power Plant" in Item 3. Legal Proceedings below.)

***Nuclear Fuel Disposal***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice ("DOJ") and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. The settlement agreement also provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. Through 2016, the Utility has been awarded an additional $99 million through these annual submissions, including $28 million for costs incurred between June 1, 2014 and May 31, 2015. The claim for the period June 1, 2015 through May 31, 2016 is currently under review by the DOE. These proceeds are being refunded to customers through rates. The settlement agreement, as amended, does not address costs incurred for spent fuel storage beyond 2016; an extension of the agreement for costs through 2019 is pending DOJ approval. Costs beyond 2016 could be subject to future litigation. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

## ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results can be affected by many factors, including estimates and assumptions used in the critical accounting policies described in MD&A, that can cause their actual financial results to differ materially from historical results or from anticipated future financial results. The following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with MD&A and the consolidated financial statements and related notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this Form 10-K. Any of these factors, in whole or in part, could materially affect PG&E Corporation's and the Utility's business, results of operations, financial condition, and stock price.

### Risks Related to the Outcome of Enforcement Matters, Investigations, and Regulatory Proceedings

***PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the Butte fire.***

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of approximately $900 million. Such insurance coverage is subject to the terms and limitations of the applicable policies and may not be sufficient to cover the Utility's ultimate liability.

The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may change. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition and the results of operations during the period such change occurred.

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals. (For more information, see "Enforcement and Litigation Matters" in Item 7. MD&A and in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

***PG&E Corporation's and the Utility's future financial results may be materially affected by the outcomes of the CPUC's investigative enforcement proceedings against the Utility, other known enforcement matters, and other ongoing state and federal investigations and requests for information. The Utility also could incur material costs and fines in connection with future investigations, citations, audits, or enforcement actions.***

The Utility could incur material charges, including fines and other penalties, in connection with a potential settlement, or litigated outcome of the CPUC's investigation of the Utility's compliance with the CPUC's rules regarding ex parte communications. While on October 14, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility submitted a status report to the CPUC which proposed an update to the framework for resolving the proceeding and included a total of 164 communications in the scope of the proceeding, the Utility expects that the other parties may argue that the number of violations exceeds the 164 communications referenced in the status report either because a single communication may have violated more than one rule or because they believe some of the material provided during discovery constitutes impermissible ex parte communications. The Utility expects to contest many of these assertions. If the matter does not settle, the CPUC will determine which communications included within the scope of the proceeding were in violation of its rules. The CPUC will also determine whether to impose penalties or other remedies, as a result of a potential settlement or otherwise. The CPUC can impose fines up to $50,000 for each violation, and up to $50,000 per day if the CPUC determines that the violation was continuing. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. While it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations, such fines or penalties could be significant and materially affect PG&E Corporation's and the Utility's liquidity and results of operations. (See the discussion under the heading "Regulatory Matters" in MD&A.)

The Utility also is a target of a number of investigations and government requests for information. In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The Utility was also contacted by certain other federal agencies with requests for information. While the Utility believes that these requests for information are routine, their outcome is uncertain. The Utility also is unable to predict the outcome of pending investigations, including whether any charges will be brought against the Utility.

If these investigations or requests for information result in enforcement action against the Utility, the Utility could incur additional fines or penalties or suffer negative consequences described above in the immediately preceding risk factor. In addition, a negative outcome in any of these investigations or future enforcement actions may negatively affect the outcome of future ratemaking and regulatory proceedings; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations.

The Utility may incur fines and penalties in connection with the Utility's efforts to identify and remove encroachments from transmission pipeline rights of way and the Penalty Decision. The Penalty Decision requires the SED to review the Utility's gas transmission operations (including the Utility's compliance with the remedies ordered by the Penalty Decision) and to perform annual audits of the Utility's record-keeping practices for a minimum of ten years. The SED could impose fines on the Utility or require the Utility to incur unrecoverable costs, or both, based on the outcome of these future audits. In addition, although PG&E Corporation and the Utility do not currently face the possibility of fines or penalties in the first phase of the CPUC's pending investigation into the Utility's safety culture since it has been categorized as rate setting, it is uncertain how a next phase, if any, would be categorized. (See the discussion under the heading "Regulatory Matters" in MD&A.)

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and resource adequacy requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; compliance with CPUC general orders or other applicable CPUC decisions or regulations; federal electric reliability standards; and environmental compliance. CPUC staff could impose penalties on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds could have a material effect on PG&E Corporation's and the Utility's financial results.

***PG&E Corporation's and the Utility's future financial results could be materially affected by the conviction of the Utility in the federal criminal proceeding and by the debarment proceeding.***

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court issued a judgment of conviction against the Utility. The court sentenced the Utility to a five-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service. The Utility has decided not to appeal the convictions.

The probation includes a requirement that the Utility not commit any local, state or federal crimes during the probation period. As part of the probation, the Utility is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017.

At December 31, 2016, PG&E Corporation and the Utility's Consolidated Balance Sheets included a $3 million accrual in connection with this matter. The Utility could incur material costs and additional penalties, not recoverable through rates, in the event of non-compliance with the terms of its probation and in connection with the monitorship (including but not limited to the monitor's compensation or costs resulting from recommendations of the monitor).

Also, in September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the San Bruno explosion and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. On December 21, 2016, the Utility and the DOI entered into an interim administrative agreement that reflects the DOI's determination that the Utility remains eligible to contract with federal government agencies while the DOI determines whether any further action is necessary to protect the federal government's business interests. The agreement will be effective until superseded by an amended agreement or determination. The agreement also provides that the DOI is still conducting a review to determine whether the Utility has an effective compliance and ethics program and that the DOI is required to use its best efforts to complete its review before the end of 2017. If the DOI determines that the Utility's program is not generally effective in preventing and detecting criminal conduct, the Utility may be required to enter into an amended administrative agreement and implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third party monitor(s).

The Utility's conviction and the outcome of the debarment proceeding could harm the Utility's relationships with regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, they could negatively affect the outcome of future ratemaking and regulatory proceedings, for example by, enabling parties to argue that the Utility should not be allowed to recover costs that the parties allege are somehow related to the criminal charges on which the Utility was found guilty. They could also result in increased regulatory or legislative scrutiny with respect to various aspects of how the Utility's business is conducted or organized. As discussed under the heading "Regulatory Matters" in Item 7. MD&A, the SED continues evaluating PG&E Corporation's and the Utility's organizational culture and governance in the CPUC's pending investigation to examine the Utility's safety culture.

***PG&E Corporation's and the Utility's financial results primarily depend on the outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its operating expenses and capital expenditures so that it is able to earn its authorized rate of return in a timely manner.***

As a regulated entity, the Utility's rates are set by the CPUC or the FERC on a prospective basis and are generally designed to allow the Utility to collect sufficient revenues to recover reasonable costs of providing service, including a return on its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the Utility's reputation (especially as a result of the Utility's conviction in the federal criminal trial), the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and affordable electric and gas services.

The Utility also is required to incur costs to comply with legislative and regulatory requirements and initiatives, such as those relating to the development of a state-wide electric vehicle charging infrastructure, the deployment of distributed energy resources, implementation of demand response and customer energy efficiency programs, energy storage and renewable energy targets, underground gas storage, and the construction of the California high-speed rail project. The Utility's ability to recover costs, including its investments, associated with these and other legislative and regulatory initiatives will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas services.

In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial results could be materially affected if the Utility's actual costs to safely and reliably serve its customers differ from authorized or forecast costs. The Utility may incur additional costs for many reasons including changing market circumstances, unanticipated events (such as storms, fires, accidents, catastrophic or other events affecting the Utility's operations), or compliance with new state laws or policies. Although the Utility may be allowed to recover some or all of the additional costs, there may be a substantial time lag between when the Utility incurs the costs and when the Utility is authorized to collect revenues to recover such costs. Alternatively, the CPUC or the FERC may disallow costs that they determine were not reasonably or prudently incurred by the Utility.

The Utility's ability to recover its costs also may be affected by the economy and its impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers or the level of uncollectible bills could increase. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base.

Changes in commodity prices also may have an adverse effect on the Utility's ability to timely recover its operating costs and earn its authorized ROE. Although the Utility generally recovers its electricity and natural gas procurement costs from customers as "pass-through" costs, a significant and sustained rise in commodity prices could create overall rate pressures that make it more difficult for the Utility to recover its costs that are not categorized as "pass-through" costs. To relieve some of this upward rate pressure, the CPUC could authorize lower revenues than the Utility requested or disallow full cost recovery.

***PG&E Corporation's and the Utility's financial results depend upon the Utility's continuing ability to recover "pass-through" costs, including electricity and natural gas procurement costs, from customers in a timely manner. The CPUC may disallow procurement costs for a variety of reasons. In addition, the Utility's ability to recover these costs could be affected by the loss of Utility customers and decreased new customer growth, if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch" and prudent administration of power purchase agreements in compliance with its CPUC-approved long-term procurement plan. The CPUC could disallow procurement costs incurred by the Utility if the CPUC determines that the Utility did not comply with these principles or if the Utility did not comply with its procurement plan.

Further, the contractual prices for electricity under the Utility's current or future power purchase agreements could become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to adverse economic conditions or the loss of the Utility's customers to other retail providers. In particular, the Utility will incur additional costs to procure renewable energy to meet the higher targets established by California SB 350 that became effective on January 1, 2016. Despite the CPUC's current approval of the contracts, the CPUC could disallow contract costs in the future if it determines that the costs are unreasonably above market.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by whether the CAISO wholesale electricity market continues to function effectively. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended which could result in excessive market prices. The CPUC could prohibit the Utility from passing through the higher costs of electricity to customers. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's then-newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreasing bundled load that occurs through municipalization of the Utility's facilities, an increase in the number of CCAs who provide electricity to their residents, and an increase in the number of consumers who become direct access customers of alternative generation providers. (See "Competition in the Electricity Industry" in Item 1.) As the number of bundled customers (i.e., those customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase as the Utility would have a smaller customer base from which to recover certain procurement costs. Although the Utility is permitted to collect non-bypassable charges for above market generation-related costs incurred on behalf of former customers, the charges may not be sufficient for the Utility to fully recover these costs. In addition, the Utility's ability to collect non-bypassable charges has been, and may continue to be, challenged by certain customer groups. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering ("NEM"), which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pressure on remaining customers. In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers will be required to pay an interconnection fee, will go on time of use rates, and will be required to pay some non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. However, the resulting rules will still put upward rate pressure on remaining customers, and remove the cap on the number of NEM customers. Significantly higher bills for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers. The CPUC states that it intends to revisit these rules in 2019.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments. If the number of the Utility's customers decreases or grows at a slower rate than anticipated, the Utility's level of capital investment would likely decline as well, in turn leading to a slower growth in rate base and earnings. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could adversely impact PG&E Corporation's and the Utility's financial results.

The CPUC has begun to implement rate reform to allow residential electric rates to more closely reflect the utilities' actual costs of providing service and decrease cost-subsidization among customer classes. Many aspects of rate reform are not yet finalized, including time-of-use rates and whether the utilities can impose a fixed charge on certain customers. If the Utility is unable to recover a material portion of its procurement costs and/or if the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, the wide deployment of distributed generation, and the development of new electricity generation and energy storage technologies, PG&E Corporation's and the Utility's financial results could be materially affected.

**Risks Related to Liquidity and Capital Requirements**

***PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.***

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, pay fines that may be imposed in the future, as well as costs related to rights-of-way and legal and regulatory costs. PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation's and the Utility's credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including the pending CPUC investigations and ratemaking proceedings. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, volatility in electricity or natural gas prices, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under "Enforcement and Litigation Matters" in Item 7. MD&A. The negative publicity and the uncertainty about the outcomes of these matters may undermine confidence in management's ability to execute its business strategy and restore a constructive regulatory environment, which could adversely impact PG&E Corporation's stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation and PG&E Corporation could be required to contribute capital to the Utility to enable the Utility to fulfill its obligation to serve. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

***PG&E Corporation's ability to meet its debt service and other financial obligations and to pay dividends on its common stock depends on the Utility's earnings and cash flows.***

PG&E Corporation is a holding company with no revenue generating operations of its own. The Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. Under the CPUC's rules applicable to utility holding companies, the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company and PG&E Corporation's Board of Directors give "first priority" to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC has interpreted this "first priority" obligation to include the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." In addition, before the Utility can pay common stock dividends to PG&E Corporation, the Utility must maintain its authorized capital structure with an average 52% equity component.

If the Utility were required to pay a material amount of fines or incur material unrecoverable costs in connection with the terms of the probation or monitorship, the pending CPUC investigations, or other enforcement matters, it would require incremental equity contributions from PG&E Corporation to restore its capital structure. PG&E Corporation common stock issuances used to fund such equity contributions could materially dilute EPS. (See "Liquidity and Financial Resources" in Item 7. MD&A.) Further, if PG&E Corporation were required to infuse the Utility with significant capital or if the Utility was unable to distribute cash to PG&E Corporation, or both, PG&E Corporation may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend, or meet other obligations.

PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%.

**Risks Related to Operations and Information Technology**

***The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial results. The Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event, or may not become available at a reasonable cost, or available at all.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. (See "Electric Utility Operations" and "Natural Gas Utility Operations" in Item 1. Business.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives. The Utility's ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond the Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;

- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;

- failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;

- a prolonged statewide electrical black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;

- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees or the public, environmental damage, or reputational damage;

- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;

- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;

- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wild land fire or natural gas explosion), and the failure to respond effectively to a catastrophic event;

- inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;

- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wild land and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;

- operator or other human error;

- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;

- construction performed by third parties that damage the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines;

- the release of hazardous or toxic substances into the air, water, or soil, including, for example, gas leaks from natural gas storage facilities; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and

- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war.

The occurrence of any of these events could interrupt fuel supplies; affect demand for electricity or natural gas; cause unplanned outages or reduce generating output; damage the Utility's assets or operations; damage the assets or operations of third parties on which the Utility relies; damage property owned by customers or others; and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, and to compensate third parties.

In particular, the Utility may incur material liability in connection with the Butte fire. (See "PG&E Corporation and the Utility may incur material liability in connection with Butte Fire" above.) Additionally, on January 12, 2017, a residential structure fire occurred in Yuba City, California, resulting in the collapse of the house and injuries to two persons inside the house. The CPUC, a third-party engineering firm, and local fire and police officials are investigating the origin and cause of the incident. The Utility may incur material costs, including as a result of these investigations or any proceedings that could be commenced in connection with this incident.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities or the construction or demolition or facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions.

Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial results. Future insurance coverage may not be available at rates and on terms as favorable as the Utility's current insurance coverage or may not be available at all.

Further, California law includes a doctrine of inverse condemnation that is routinely invoked in California for wildfire damages. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages and takings as a result of the design, construction and maintenance of utility facilities, including its electric transmission lines. As a result of the strict liability standard applied to wildfires, recent losses recorded by insurance companies, the risk of increase of wildfires including as a result of the ongoing drought, and the Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at comparable cost and terms as the Utility's current insurance coverage, or at all. In addition, the Utility is unable to predict whether it would be allowed to recover in rates the increased costs of insurance or the costs of any uninsured losses.
If the amount of insurance is insufficient or otherwise unavailable, or if the Utility is unable to recover in rates the costs of any uninsured losses, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected.

***The Utility's operational and information technology systems could fail to function properly or be improperly accessed or damaged by third parties (including cyber-attacks and physical acts) or damaged by severe weather, natural disasters, or other events. Any of these events could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense or liability to third parties.***

The operation of the Utility's extensive electricity and natural gas systems relies on evolving and increasingly complex operational and information technology systems and network infrastructures that are interconnected with the systems and network infrastructure owned by third parties. All of the Utility's operational and technology systems and network infrastructure are vulnerable to disability or failures in the event of cyber-attacks and physical acts. Cyber-attacks are increasingly sophisticated and may include computer hacking, viruses, malware, social engineering, denial of service attacks, ransomware, destructive malware, or other means of disruption, destruction, or unauthorized access, acquisition or control. In addition, hardware, software, or applications the Utility develops or procures from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information security. Physical attacks may include acts of sabotage, acts of war, acts of terrorism, or other physical acts. The Utility's operational and information technology systems and networks are deemed critical infrastructure, and any failure or decrease in their functionality could, among other things, cause harm to the public or employees, significantly disrupt operations, negatively impact the Utility's ability to generate, transport, deliver and store energy and gas, or otherwise operate in the most efficient manner or at all, undermine the Utility's performance of critical business functions, damage the Utility's assets or operations or those of third parties, and lead to reputational harm. As a result, such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, investigations, and regulatory actions that could result in fines and penalties, and loss of customers, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require ongoing maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. The Utility often relies on third-party vendors to host, maintain, modify, and update its systems and these third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience internal or external security incidents. Any incidents, disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification of existing systems or implementation of new systems could result in increased costs, the inability to track or collect revenues, or diversion of management's and employees' attention and resources, or negatively affect the Utility's ability to maintain effective financial controls or timely file required regulatory reports. The Utility also could be subject to patent infringement claims arising from the use of third-party technology by the Utility or by a third-party vendor.

In addition, the Utility's information systems contain confidential information, including information about customers and employees. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject the Utility to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm the Utility's reputation.

The Utility and its third party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to the Utility's information technology systems, or confidential data, or to disrupt the Utility's operations. None of these attempts or breaches has individually or in the aggregate resulted in a security incident with a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent the unauthorized access to its systems, infrastructure, or data, or the disruption of its operations, either of which could materially affect PG&E Corporation's and the Utility's financial condition and results of operations.

While the Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents, there is no guarantee that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.

***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire.***

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial results. In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application includes a joint proposal between the Utility and certain interested parties, entered into on June 20, 2016. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before the licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial results.

In addition, in order to retain highly skilled personnel necessary to safely operate Diablo Canyon during the remaining years of operations, the Utility will incur costs in connection with (i) an employee retention program to ensure adequate staffing levels at Diablo Canyon, and (ii) an employee retraining and development program, to facilitate redeployment of a portion of Diablo Canyon personnel to the decommissioning project and elsewhere in the company. The Utility currently estimates that the additional cost of the employee retention program and the employee retraining and development program will be approximately $350 million. The Joint Proposal seeks confirmation from the CPUC that these costs will be recovered through the Utility's nuclear decommissioning electric rates. The employee retention and retraining and development programs are subject to bargaining with the Utility's labor unions. The Utility will also incur costs in connection with an employee severance program. The severance program was previously approved by the CPUC in prior nuclear decommissioning ratemaking proceedings.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See "Regulatory Environment" in Item 1. Business.) If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon before the licenses expire in 2024 and 2025. At December 31, 2016, the Utility's unrecovered investment in Diablo Canyon was $1.7 billion.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. If the Utility obtains contingent approvals referred to herein that will result in retiring Diablo Canyon at the end of the current NRC operating licenses, the Utility will not be required to install cooling towers or implement alternative measures in order to comply with the California State Water Board Once-Through Cooling Water Policy, thus eliminating the regulatory uncertainty regarding the measures that could have been imposed on the Utility or of incurring a material charge related thereto. Even if the Utility is ultimately not required to install cooling towers, under the State Water Board's interim mitigation measures applicable to Diablo Canyon's operations prior to 2025, starting in 2016, it will be required to make payments to the California Coastal Conservancy to fund various environmental mitigation projects, that the Utility does not expect to exceed $5 million per year.

On June 28, 2016 the California State Lands Commission approved an extension of the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon, to run concurrently with Diablo Canyon's current operating licenses. The Utility will be required to obtain an additional lease extension from the State Lands Commission to cover the period of time necessary to decommission the facility. The State Lands Commission and California Coastal Commission will evaluate appropriate environmental mitigation and development conditions associated with the decommissioning project, the costs of which could be substantial.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial results could be materially affected.

**Risks Related to Environmental Factors**

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial results.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. (For more information, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. (See "Environmental Regulation" in Item 1.) The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial results. Their financial results also can be materially affected by changes in estimated costs and by the extent to which actual remediation costs differ from recorded liabilities.

***The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.***

The Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns, rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. While snowpack in the Sierra Nevada Mountains has been at higher than normal levels this winter, California has experienced ongoing drought in the past. If temperatures and the levels of precipitation in the Utility's service territory continue to change, that could impact the levels of snowpack in the Sierra Nevada Mountains. As a result, the Utility's hydroelectric generation could change and the Utility would need to consider managing or acquiring additional generation.
If the Utility increases its reliance on conventional generation resources to replace hydroelectric generation and to meet increased

customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, increasing temperatures and lower levels of precipitation could increase the occurrence of wildfires in the Utility's service territory causing damage to the Utility's facilities or the facilities of third parties on which the Utility relies to provide service, damage to third parties for loss of property, personal injury, or loss of life. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including hydroelectric assets such as dams and canals, and the electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

**Other Risk Factors**

***PG&E Corporation's and the Utility's financial results could be materially affected as a result of political and legislative developments.***

The Utility's financial results could be materially affected as a result of the recent change in federal administration from President Barack Obama to President Donald Trump. For example, the new administration has indicated tax reform as a priority. Tax reform outlines produced by both President Trump and the Tax Reform Task Force include proposals related to federal tax rates, deductions for state income taxes (and potentially property tax), interest expense deduction, capital expenditure deduction, and expensing plant. It is unclear what tax reform may be ultimately adopted. It is generally expected that a tax reform bill will be introduced in early 2017.

***The Utility may be required to incur substantial costs in order to obtain or renew licenses and permits needed to operate the Utility's business and the Utility may be subject to fines and penalties for failure to comply or obtain license renewal.***

The Utility must comply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility's hydroelectric generation facilities, and those issued by environmental and other federal, state and local governmental agencies. Many of the Utility's capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizations, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility. If a license or permit is not renewed for a particular facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs. Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Utility's compliance costs. In particular, in connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility. In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has not been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, licenses, ordinances, or other requirements, or if the Utility cannot recover the increase in associated compliance and other costs in a timely manner, PG&E Corporation's and the Utility's financial results could be materially affected.

***Poor investment performance or other factors could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. The performance of the debt and equity markets affects the value of plan assets and trust assets. A decline in the market value may increase the funding requirements for these plans and trusts. The cost of providing pension and other postretirement benefits is also affected by other factors, including interest rates used to measure the required minimum funding levels, the rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by the rates of return on trust assets, changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. (See Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in Item 8.) If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans or if actual nuclear decommissioning costs exceed the amount of nuclear decommissioning trust funds and the Utility is unable to recover the contributions or additional costs in rates, PG&E Corporation's and the Utility's financial results could be materially affected.

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility's workforce is aging and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements with the unions or if tentative new agreements are not ratified by their members. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceedings. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

**ITEM 2. PROPERTIES**

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under "Electric Utility Operations" and "Natural Gas Utility Operations." The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11 million square feet of real property, including 9 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire in 2022.

The Utility currently owns approximately 167,000 acres of land, including approximately 140,000 acres of watershed lands. In 2002 the Utility agreed to implement its "Land Conservation Commitment" ("LCC") to permanently preserve the six "beneficial public values" on all the watershed lands through conservation easements or equivalent protections, as well as to make approximately 70,000 acres of the watershed lands available for donation to qualified organizations. The six "beneficial public values" being preserved by the LCC include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Utility's goal is to implement all the transactions needed to implement the LCC by the end of 2018, subject to securing all required regulatory approvals.

**ITEM 3. LEGAL PROCEEDINGS**

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

**Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission**

On April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. In January 2016, the CPUC closed the investigative proceedings. The total penalty included (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million.

The Utility refunded the $400 million to its customers in the second quarter of 2016 and paid the $300 million fine in the third quarter of 2015. On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case, which applies $689 million of the $850 million penalty to capital expenditures. The Utility is precluded from including these capital costs in rate base. The final phase two decision also approves the Utility's list of programs and projects that meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty. For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

**Federal Criminal Trial**

On June 14, 2016, a federal criminal trial against the Utility began in the United States District Court for the Northern District of California, in San Francisco, on 12 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility obstructed the NTSB investigation into the cause of the San Bruno accident. On July 26, 2016, the court granted the government's motion to dismiss one count alleging that the Utility knowingly and willfully failed to retain a strength test pressure record with respect to a distribution feeder main, thereby reducing the total number of counts from 13 to 12.

On August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act.

On January 26, 2017, the court issued a judgment of conviction sentencing the Utility to a five-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service. The Utility has decided not to appeal the convictions. The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017. For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.

**Litigation Related to the San Bruno Accident and Natural Gas Spending**

As of December 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the *San Bruno Fire Derivative Cases* and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are *Tellardin v. Anthony F. Earley, Jr.,. et al., Iron Workers Mid-South Pension Fund v. Johns, et al.,* and *Bushkin v. Rambo et al*.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated *San Bruno Fire Derivative Cases* pending conclusion of the federal criminal proceedings against the Utility. On November 16, 2016, counsel in the four consolidated *San Bruno Fire Derivative* cases, as well as counsel in the *Tellardin* action, appeared for a status conference in the San Mateo Superior Court. The court reaffirmed that all proceedings in these actions were stayed until the conclusion of the Utility's federal criminal proceeding, at which point they were directed to meet and confer and report back to the court. The parties completed a mediation session on December 8-9, 2016 and continue discussions about the potential resolution of the matter. These actions remain stayed.

*Bushkin v. Rambo et al*., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit *Iron Workers Mid-South Pension Fund v. Johns, et al*., discussed below. The plaintiff in the *Bushkin* lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the *Bushkin* plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the *San Bruno Fire Derivative Cases* has been lifted, or, in the alternative, a demurrer asking the court to dismiss plaintiff's petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation's motion, and indicated that plaintiff's petition was stayed pending resolution of the criminal matter against the Utility. On January 13, 2017, the parties submitted a joint case management statement advising the court that, because the Utility had not yet been sentenced, the case should remain stayed until at least March 10, 2017, when the parties will advise the court of further developments. While the Utility was sentenced in the federal criminal proceeding on January 26, 2017, this matter remains stayed until at least March 10, 2017.

The *Iron Workers* action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the *San Bruno Fire Derivative Cases*. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court's request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the *San Bruno Fire Derivative Cases*. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the stay pending the resolution of the federal criminal proceeding against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017. This matter remains stayed until at least March 15, 2017.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

**Butte Fire Litigation**

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling cases. The next case management conference is scheduled for March 2, 2017.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes it was not negligent; however, there can be no assurance that a court or jury would agree with the Utility. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and other damages that the Utility could be liable for under the theories of inverse condemnation and/or negligence.

For additional information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

**Other Enforcement Matters**

Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with electric and natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, and other enforcement matters. See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

**Diablo Canyon Nuclear Power Plant**

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement was that the Central Coast Board renew Diablo Canyon's permit.

However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists to develop additional information on possible mitigation measures for Central Coast Board staff. In 2005, the Central Coast Board reviewed the scientists' draft report recommending several such mitigation measures, but no action was taken.

Subsequently, the California State Water Resources Control Board adopted a Once-Through Cooling Water Policy in May 2010 which requires Diablo Canyon to be in compliance with the policy by December 2024 and allows for alternative compliance measures at nuclear power plants.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. The Utility expects that the State Board's OTC Policy and its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Water Board and the California Attorney General's Office. Also, as required under the State Board's OTC Policy, beginning in 2017, the Utility will pay an annual interim mitigation fee until operations cease at the end of the current licenses.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on the Utility's financial condition or results of operations.

**Venting Incidents in San Benito County**

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called "pigs" that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline must be released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility's transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County district attorney notified the Utility in December 2014 that it was contemplating bringing a civil legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. In January 2017, the Utility and the district attorney reached an agreement on a stipulated judgement that resolves the matter. The stipulated judgment includes a fine of approximately $175,000. In addition, a $75,000 fine will be held in abeyance for 5 years, and would be payable to the San Benito County district attorney in case of non-compliance with certain remedial requirements of the stipulated judgment. The stipulated judgment was executed by the court on January 27, 2017.

**Transformer Oil Release in Sonoma County**

During a rain storm in February 2015, transformer oil was released into an underground vault in the City of Santa Rosa, in Sonoma County, while a Utility crew was replacing a broken transformer. Following further rains, the oil released from the vault and reached a nearby creek. The event was investigated by Santa Rosa Fire Department, the local environmental enforcement authority, and later referred to the Sonoma County District Attorney's Office. In May 2016, the District Attorney informed the Utility that it would seek penalties and costs in excess of $100,000 for alleged violations of several sections of the California Health and Safety and California Government codes which prohibit unauthorized spills or releases of oil into waters of the state and require that releases be reported to the Office of Emergency Services. In November 2016, the Utility and the Sonoma County district attorney reached an agreement on a stipulated judgment that resolves the matter. The stipulated judgment includes a fine of $80,000, reimbursement of enforcement costs of $40,000, and injunctive provisions requiring improvements to the Utility's vault dewatering procedure and training. In November 2016, the court approved the stipulated judgment.

**ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

**EXECUTIVE OFFICERS OF THE REGISTRANTS**

The following individuals serve as executive officers [1] of PG&E Corporation and/or the Utility, as of February 16, 2017. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| Anthony F. Earley, Jr. [2] | 67 | Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation | September 13, 2011 to present |
| | | Executive Chairman of the Board, DTE Energy Company | October 1, 2010 to September 12, 2011 |
| Nickolas Stavropoulos [2] | 58 | President, Gas | September 15, 2015 to present |
| | | President, Gas Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Gas Operations | June 13, 2011 to August 16, 2015 |
| Geisha J. Williams [2] | 55 | President, Electric | September 15, 2015 to present |
| | | President, Electric Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Electric Operations | June 1, 2011 to August 16, 2015 |
| Jason P. Wells | 39 | Senior Vice President and Chief Financial Officer, PG&E Corporation | January 1, 2016 to present |
| | | Vice President, Business Finance | August 1, 2013 to December 31, 2015 |
| | | Vice President, Finance | October 1, 2011 to July 31, 2013 |
| John R. Simon | 52 | Executive Vice President, Corporate Services and Human Resources, PG&E Corporation | August 17, 2015 to present |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | April 16, 2007 to August 16, 2015 |
| Karen A. Austin | 55 | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| | | President, Consumer Electronics, Sears Holdings | February 2009 to May 2011 |

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|---|---|---|---|
| Desmond A. Bell [3] | 54 | Senior Vice President, Safety and Shared Services | January 1, 2012 to present |
| Helen A. Burt [3] | 60 | Senior Vice President, External Affairs and Public Policy, PG&E Corporation and Pacific Gas and Electric Company | September 30, 2015 to present |
| | | Senior Vice President, Corporate Affairs, PG&E Corporation | September 18, 2014 to September 30, 2015 |
| | | Senior Vice President and Chief Customer Officer | February 27, 2006 to September 17, 2014 |
| Loraine M. Giammona | 49 | Senior Vice President and Chief Customer Officer | September 18, 2014 to present |
| | | Vice President, Customer Service | January 23, 2012 to September 17, 2014 |
| | | Regional Vice President, Customer Care, Comcast Cable | November 2002 to January 2012 |
| Edward D. Halpin | 55 | Senior Vice President, Generation and Chief Nuclear Officer | March 28, 2016 to present |
| | | Senior Vice President, Power Generation and Chief Nuclear Officer | September 8, 2015 to March 27, 2016 |
| | | Senior Vice President and Chief Nuclear Officer | April 2, 2012 to September 8, 2015 |
| | | President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company | December 2009 to March 2012 |
| Patrick M. Hogan | 53 | Senior Vice President, Electric Operations | February 1, 2017 to present |
| | | Senior Vice President, Electric Transmission and Distribution | March 1, 2016 to January 31, 2017 |
| | | Vice President, Electric Strategy and Asset Management | September 8, 2015 to February 29, 2016 |
| | | Vice President, Electric Operations, Asset Management | November 18, 2013 to September 7, 2015 |
| | | Senior Vice President, Transmission and Distribution Engineering and Design, BC Hydro | October 2011 to November 2013 |
| Julie M. Kane | 58 | Senior Vice President and Chief Ethics and Compliance Officer, PG&E Corporation and Pacific Gas and Electric Company | May 18, 2015 to present |
| | | Vice President, General Counsel and Compliance Officer, North America, Avon Products, Inc. | September 30, 2013 to March 31, 2015 |
| | | Vice President, Ethics and Compliance, Novartis Corporation | January 1, 2010 to August 31, 2015 |
| Steven E. Malnight | 44 | Senior Vice President, Regulatory Affairs | September 18, 2014 to present |
| | | Vice President, Customer Energy Solutions | May 15, 2011 to September 17, 2014 |
| | | Vice President, Integrated Demand Side Management | July 1, 2010 to May 14, 2011 |
| Dinyar B. Mistry | 55 | Senior Vice President, Human Resources and Chief Diversity Officer, PG&E Corporation and Pacific Gas and Electric Company | February 1, 2017 to present |

| | | | |
|---|---|---|---|
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | June 1, 2016 to January 31, 2017 |
| | | Senior Vice President, Human Resources, Chief Financial Officer, and Controller | March 1, 2016 to May 31, 2016 |
| | | Senior Vice President, Human Resources and Controller, PG&E Corporation | March 1, 2016 to May 31, 2016 |
| | | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to February 28, 2016 |
| | | Vice President and Controller, PG&E Corporation | March 8, 2010 to February 28, 2016 |
| Hyun Park [(4)] | 55 | Senior Vice President and General Counsel, PG&E Corporation | November 13, 2006 to present |
| Jesus Soto, Jr. | 49 | Senior Vice President, Gas Operations | September 8, 2015 to present |
| | | Senior Vice President, Engineering, Construction and Operations | September 16, 2013 to September 8, 2015 |
| | | Senior Vice President, Gas Transmission Operations | May 29, 2012 to September 15, 2013 |
| | | Vice President, Operations Services, El Paso Pipeline Group | May 2007 to May 2012 |
| Fong Wan | 55 | Senior Vice President, Energy Policy and Procurement | September 8, 2015 to present |
| | | Senior Vice President, Energy Procurement | October 1, 2008 to September 8, 2015 |
| David S. Thomason | 41 | Vice President, Chief Financial Officer, and Controller | June 1, 2016 to present |
| | | Vice President and Controller, PG&E Corporation | June 1, 2016 to present |
| | | Senior Director, Financial Forecasting and Analysis | March 2, 2015 to May 31, 2016 |
| | | Senior Director, Corporate Accounting | March 2, 2014 to March 1, 2015 |
| | | Senior Director, Financial Forecasting and Analysis | September 1, 2012 to March 1, 2014 |
| | | Director, Planning, Forecasting and Reporting | October 3, 2011 to August 31, 2012 |

(1) Mr. Earley, Mr. Stavropoulos, Ms. Williams, Mr. Simon, Ms. Burt, Ms. Kane, Mr. Mistry, Mr. Park, and Mr. Wells are executive officers of both PG&E Corporation and the Utility. All other listed officers are executive officers of the Utility only.
(2) On November 14, 2016, the Board of Directors of PG&E Corporation elected Mr. Earley to the role of Executive Chair of the Board of PG&E Corporation and Ms. Williams to the role of Chief Executive Officer and President of PG&E Corporation, both effective March 1, 2017. Also on November 14, 2016, the Board of Directors of the Utility elected Mr. Stavropoulos as President and Chief Operating Officer of the Utility effective March 1, 2017.
(3) Mr. Bell and Ms. Burt will step down from their positions effective March 1, 2017.
(4) Mr. Park will step down from his position effective March 1, 2017 but is expected to remain with PG&E Corporation until September 1, 2017.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 7, 2017, there were 56,835 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and is traded under the symbol "PCG". The high and low closing prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth in the table entitled "Quarterly Consolidated Financial Data (Unaudited)" which appears after the Notes to the Consolidated Financial Statements in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock appears in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 of the Notes to the Consolidated Financial Statements in Item 8 and in "Liquidity and Financial Resources – Dividends" in Item 7 below.

***Sales of Unregistered Equity Securities***

PG&E Corporation made equity contributions to the Utility totaling $95 million during the quarter ended December 31, 2016. PG&E Corporation did not make any sales of unregistered equity securities during 2016 in reliance on an exemption from registration under the Securities Act of 1933, as amended.

***Issuer Purchases of Equity Securities***

During the quarter ended December 31, 2016, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. Also, during the quarter ended December 31, 2016, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

## ITEM 6. SELECTED FINANCIAL DATA

| (in millions, except per share amounts) | 2016 | 2015 | 2014 | 2013 | 2012 |
|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,666 | $ 16,833 | $ 17,090 | $ 15,598 | $ 15,040 |
| Operating income | 2,177 | 1,508 | 2,450 | 1,762 | 1,693 |
| Net income | 1,407 | 888 | 1,450 | 828 | 830 |
| Net earnings per common share, basic [1] | 2.79 | 1.81 | 3.07 | 1.83 | 1.92 |
| Net earnings per common share, diluted | 2.78 | 1.79 | 3.06 | 1.83 | 1.92 |
| Dividends declared per common share [2] | 1.93 | 1.82 | 1.82 | 1.82 | 1.82 |
| **At Year-End** | | | | | |
| Common stock price per share | $ 60.77 | $ 53.19 | $ 53.24 | $ 40.28 | $ 40.18 |
| Total assets [3] | 68,598 | 63,234 | 60,228 | 55,693 | 52,530 |
| Long-term debt (excluding current portion) [3] | 16,220 | 15,925 | 15,151 | 12,805 | 12,598 |
| Capital lease obligations (excluding current portion) [4] | 31 | 49 | 69 | 90 | 113 |
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,667 | $ 16,833 | $ 17,088 | $ 15,593 | $ 15,035 |
| Operating income | 2,181 | 1,511 | 2,452 | 1,790 | 1,695 |
| Income available for common stock | 1,388 | 848 | 1,419 | 852 | 797 |
| **At Year-End** | | | | | |
| Total assets [5] | 68,374 | 63,037 | 59,964 | 55,137 | 52,003 |
| Long-term debt (excluding current portion) [5] | 15,872 | 15,577 | 14,799 | 12,805 | 12,247 |
| Capital lease obligations (excluding current portion) [4] | 31 | 49 | 69 | 90 | 113 |

(1) See "Overview – Summary of Changes in Net Income and Earnings per Share" in Item 7. MD&A.
(2) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources – Dividends" in MD&A in Item 7 and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 in Item 8.
(3) In accordance with ASU No. 2015-03, PG&E Corporation restated $105 million in 2015, $101 million in 2014, $88 million in 2013, and $81 million in 2012, of debt issuance costs. Total assets and total liabilities were each reduced by the amounts above with no impact to net income or total shareholders' equity previously reported.
(4) The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.
(5) In accordance with ASU No. 2015-03, the Utility restated $103 million in 2015, $99 million in 2014, $88 million in 2013, and $80 million in 2012, of debt issuance costs. Total assets and total liabilities were each reduced by the amounts above with no impact to net income or total shareholders' equity previously reported.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility's base revenue requirements are set by the CPUC in its GRC and GT&S rate case and by the FERC in its TO rate cases based on forecast costs. Differences between forecast costs and actual costs can occur for numerous reasons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. Generally, differences between actual costs and forecast costs affect the Utility's ability to earn its authorized return (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations below). However, for certain operating costs, such as costs associated with pension and other employee benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). The Utility also collects revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, such as the costs to procure electricity or natural gas for its customers. Therefore, although these costs can fluctuate, they generally do not impact net income (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). See "Ratemaking Mechanisms" in Item 1 for further discussion.

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

**Summary of Changes in Net Income and Earnings per Share**

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS based on earnings from operations) for the year ended December 31, 2016 compared to the year ended December 31, 2015 (see "Results of Operations" below). "Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

| (in millions, except per share amounts) | Earnings [1] | EPS (diluted) |
|---|---|---|
| **Income Available for Common Shareholders - 2015** | **$ 874** | **$ 1.79** |
| Add items impacting comparability: | | |
| Fines and penalties | 578 | 1.19 |
| Pipeline-related expenses | 61 | 0.13 |
| Legal and regulatory related expenses | 35 | 0.07 |
| Natural gas matters insurance recoveries | (29) | (0.06) |
| **Earnings from Operations - 2015 [2]** | $ **1,519** | $ **3.12** |
| 2015 GT&S revenue [3] | 300 | 0.60 |
| Growth in rate base earnings | 102 | 0.20 |
| Regulatory and legal matters | 1 | - |
| Gain on disposition of SolarCity stock [4] | (14) | (0.03) |
| Increase in shares outstanding | - | (0.09) |
| Miscellaneous | (24) | (0.04) |
| **Earnings from Operations - 2016 [2]** | **$ 1,884** | **$ 3.76** |
| Less items impacting comparability: | | |
| Butte fire related costs (net of insurance) [5] | (137) | (0.27) |
| Fines and penalties [6] | (307) | (0.61) |
| Pipeline-related expenses [7] | (67) | (0.13) |
| Legal and regulatory related expenses [8] | (43) | (0.09) |
| GT&S capital disallowance [9] | (130) | (0.26) |
| GT&S revenue [10] | 193 | 0.38 |
| **Income Available for Common Shareholders - 2016** | **$ 1,393** | **$ 2.78** |

(1) All amounts presented in the table above are tax-adjusted at PG&E Corporation's tax rate of 40.75% except for fines, which are not tax deductible. See footnote (6) below.

(2) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in footnotes (5) through (10).

(3) Represents the increase in 2016 revenues authorized December 1, 2016 in the final phase two decision of the Utility's 2015 GT&S rate case.

(4) Represents the gain recognized during the year ended December 31, 2015. No comparable gain was recognized in 2016.

(5) The Utility recorded costs of $232 million (before the tax impact of $95 million) during the year ended December 31, 2016 associated with the Butte fire, net of insurance. This includes accrued charges of $750 million (before the tax impact of $306 million) related to estimated third-party claims in connection with the Butte fire, partially offset by $625 million (before the tax impact of $255 million) as probable of insurance recovery. The Utility also incurred charges of $107 million (before the tax impact of $44 million) for Utility clean-up, repair, and legal costs associated with the Butte fire.

(6) The Utility incurred costs of $498 million (before the tax impact of $191 million), during the year ended December 31, 2016 associated with fines and penalties. This includes costs of $412 million (before the tax impact of $168 million) associated with safety-related cost disallowances imposed by the CPUC in its April 9, 2015 decision in the gas transmission pipeline investigations. The Utility also recorded $57 million (before the tax impact of $23 million) for disallowances imposed by the CPUC in its final phase two decision of the 2015 GT&S rate case for prohibited *ex parte* communications. In addition, the Utility accrued fines of $26 million in connection with the final decision approved by the CPUC on August 18, 2016 in its investigation regarding natural gas distribution record-keeping practices and $3 million in connection with the maximum statutory fine imposed on January 26, 2017 in the federal criminal trial against the Utility. These fines are not tax deductible. Future fines or penalties may be imposed in connection with other enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(7) The Utility incurred costs of $113 million (before the tax impact of $46 million), during the year ended December 31, 2016 for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights of way.

(8) The Utility incurred costs of $72 million (before the tax impact of $29 million), during the year ended December 31, 2016 for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(9) The Utility incurred charges of $219 million (before the tax impact of $89 million), during the year ended December 31, 2016, for disallowed capital expenditures based on the CPUC final phase one decision dated June 23, 2016 in the 2015 GT&S rate case, including $134 million (before the tax impact of $54 million) for the disallowed portion of the 2011 through 2014 capital expenditures in excess of adopted amounts and $85 million (before the tax impact of $35 million) for the Utility's estimate of 2015 through 2018 capital expenditures that are likely to exceed authorized amounts. (See "Regulatory Matters" below for more information.)

(10) As a result of the timing of the CPUC's final phase two decision in the 2015 GT&S rate case, the Utility recorded $325 million (before the tax impact of $132 million) in excess of the 2016 authorized revenue requirement during the twelve months ended December 31, 2016.

### Key Factors Affecting Financial Results

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materially affected by the following factors:

- *The Outcome of Enforcement, Litigation, and Regulatory Matters.* The Utility's future financial results may continue to be impacted by the outcome of current and future enforcement, litigation, and regulatory matters, including the Butte fire litigation, potential costs associated with the alleged violations of the CPUC's ex parte communication rules, the cost of complying with the terms of probation and monitorship imposed in the sentencing phase of the federal criminal trial and related remedial and other measures, and potential penalties in connection with the Utility's self-report related to its customer service representatives' drug and alcohol testing program. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

- *The Timing and Outcome of Ratemaking Proceedings.* The Utility's results may be impacted by the timing and outcome of its 2017 GRC, FERC TO rate case, and petition for modification related to its cost of capital. Based on the current schedule, the Utility expects a final decision in its 2017 GRC in the first half of 2017. (See "Regulatory Matters − 2017 General Rate Case" below for more information.) In addition, settlement negotiations are ongoing related to the Utility's FERC TO rate case requesting a 2017 retail electric transmission revenue requirement. (See "Regulatory Matters − FERC Transmission Owner Rate Cases" below for more information.) Also, on February 7, 2017, the Utility filed with the CPUC a petition for modification related to its cost of capital. (See "Regulatory Matters – CPUC Cost of Capital" below for more information.) The outcome of regulatory proceedings can be affected by many factors, including arguments made by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- *The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures.* The Utility is committed to delivering safe, reliable, sustainable, and affordable electric and gas services to its customers. Increasing demands from state laws and policies relating to increased renewable energy resources, the reduction of GHG emissions, the expansion of energy efficiency programs, the development and widespread deployment of distributed generation and self-generation resources, and the development of energy storage technologies have increased pressure on the Utility to achieve efficiencies in its operations in order to maintain the affordability of its service. In any given year the Utility's ability to earn its authorized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 2017 it will incur unrecovered pipeline-related expenses ranging from $80 million to $125 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the CPUC decision in the Utility's 2015 GT&S rate case establishes various cost caps that will increase the risk of overspend over the rate case cycle. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

- *The Amount and Timing of the Utility's Financing Needs.* PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In 2016, PG&E Corporation issued $842 million of common stock and used $835 million of the cash proceeds to make equity contributions to the Utility. PG&E Corporation forecasts that it will continue issuing a material amount of equity in future years, including $400 million to $600 million in 2017, primarily to support the Utility's capital expenditures. PG&E Corporation may issue additional equity to fund

unrecoverable pipeline-related expenses and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances could have a material dilutive impact on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this 2016 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this 2016 Form 10-K. See the section entitled "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2016, 2015, and 2014. See "Key Factors Affecting Financial Results" above for further discussion about factors that could affect future results of operations.

### PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income available for common shareholders:

| (in millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Consolidated Total | $ 1,393 | $ 874 | $ 1,436 |
| PG&E Corporation | 5 | 26 | 17 |
| Utility | $ 1,388 | $ 848 | $ 1,419 |

PG&E Corporation's net income consists primarily of income taxes, interest expense on long-term debt, and other income from investments. Results include approximately $30 million and $45 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in 2015 and 2014, respectively, with no corresponding gains in 2016.

### Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2016, 2015, and 2014. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

| (in millions) | 2016 Revenues and Costs: That Impacted Earnings | 2016 Revenues and Costs: That Did Not Impact Earnings | 2016 Total Utility | 2015 Revenues and Costs: That Impacted Earnings | 2015 Revenues and Costs: That Did Not Impact Earnings | 2015 Total Utility | 2014 Revenues and Costs: That Impacted Earnings | 2014 Revenues and Costs: That Did Not Impact Earnings | 2014 Total Utility |
|---|---|---|---|---|---|---|---|---|---|
| Electric operating revenues | $ 7,955 | $ 5,910 | $ 13,865 | $ 7,442 | $ 6,215 | $ 13,657 | $ 7,059 | $ 6,597 | $ 13,656 |
| Natural gas operating revenues | 2,767 | 1,035 | 3,802 | 2,082 | 1,094 | 3,176 | 2,072 | 1,360 | 3,432 |
| **Total operating revenues** | **10,722** | **6,945** | **17,667** | **9,524** | **7,309** | **16,833** | **9,131** | **7,957** | **17,088** |
| Cost of electricity | - | 4,765 | 4,765 | - | 5,099 | 5,099 | - | 5,615 | 5,615 |
| Cost of natural gas | - | 615 | 615 | - | 663 | 663 | - | 954 | 954 |
| Operating and maintenance | 5,787 | 1,565 | 7,352 | 5,402 | 1,547 | 6,949 | 4,247 | 1,388 | 5,635 |
| Depreciation, amortization, and decommissioning | 2,754 | - | 2,754 | 2,611 | - | 2,611 | 2,432 | - | 2,432 |
| **Total operating expenses** | **8,541** | **6,945** | **15,486** | **8,013** | **7,309** | **15,322** | **6,679** | **7,957** | **14,636** |
| **Operating income** | **2,181** | **-** | **2,181** | **1,511** | **-** | **1,511** | **2,452** | **-** | **2,452** |
| Interest income [1] | | | 22 | | | 8 | | | 8 |
| Interest expense [1] | | | (819) | | | (763) | | | (720) |
| Other income, net [1] | | | 88 | | | 87 | | | 77 |
| **Income before income taxes** | | | 1,472 | | | 843 | | | 1,817 |
| Income tax provision (benefit) [1] | | | 70 | | | (19) | | | 384 |
| **Net income** | | | 1,402 | | | 862 | | | 1,433 |
| Preferred stock dividend requirement [1] | | | 14 | | | 14 | | | 14 |
| **Income Available for Common Stock** | | | **$ 1,388** | | | **$ 848** | | | **$ 1,419** |

[1] These items impacted earnings.

### Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2016, 2015, and 2014, focusing on revenues and expenses that impacted earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased $1.2 billion or 13% in 2016 compared to 2015, primarily as a result of approximately $700 million of incremental revenues authorized in the 2015 GT&S rate case and approximately $425 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case.

The Utility included the authorized increase for the 2015 GT&S rate case period in rates starting August 1, 2016. The Utility will collect, over a 36-month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. Accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. As a result, the Utility will recognize the remaining $102 million in the first quarter of 2017. (See "Regulatory Matters" below.)

The Utility's electric and natural gas operating revenues that impacted earnings increased $393 million or 4% in 2015 compared to 2014, primarily as a result of approximately $490 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case. This increase was partially offset by the absence of approximately $110 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the same period in 2014.

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings increased $385 million or 7% in 2016 compared to 2015, primarily due to $857 million in charges for third-party claims, Utility clean-up, repair, and legal costs related to the Butte fire, $219 million in permanently disallowed capital spending (see "Regulatory Matters" below), $34 million in charges recorded in connection with the final CPUC decision related to the natural gas distribution facilities record-keeping investigation, the federal criminal trial, and the atmospheric corrosion inspection self-report, $24 million in higher pipeline-related expenses and legal and regulatory related expenses during the year ended December 31, 2016, an escalation related to labor, benefits, and service contracts, and accelerated transmission and distribution project work. These increases were partially offset by $500 million in charges associated with the Penalty Decision for customer refunds and fines incurred in 2015 with no corresponding charges in 2016 and approximately $125 million in lower disallowed capital charges associated with the Penalty Decision in 2016. Additionally, the Utility recorded approximately $625 million in probable insurance recoveries related to the Butte fire in the year ended December 31, 2016 as compared to $49 million of insurance recoveries for third-party claims related to the San Bruno accident for the same period in 2015. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility's operating and maintenance expenses that impacted earnings increased $1.2 billion or 27% in 2015 compared to 2014, primarily due to $907 million in charges associated with the Penalty Decision, consisting of $400 million for the customer bill credit, an additional $100 million charge for the fine payable to the state, and $407 million of disallowed capital charges. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The increase is also due to higher labor and benefit-related expenses of approximately $100 million and fewer insurance recoveries for third-party claims and associated legal costs of $63 million related to the San Bruno accident. No further insurance recoveries related to these claims are expected. These increases were offset by $116 million in disallowed capital recorded in 2014 related to the PSEP.

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased $143 million or 5% in 2016 compared to 2015 and $179 million or 7% in 2015 compared to 2014. In 2016, the increase was primarily due to the impact of capital additions. In 2015, the increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by the FERC in the TO rate case.

*Interest Expense*

The Utility's interest expenses increased by $56 million or 7% in the year ended December 31, 2016 compared to the same period in 2015, primarily due to the issuance of additional long-term debt. The Utility's interest expenses increased by $43 million or 6% in the year ended December 31, 2015 compared to the same period in 2014, primarily due to the issuance of long-term debt.

*Interest Income and Other Income, Net*

There were no material changes to interest income and other income, net for the periods presented.

*Income Tax Provision*

The Utility's income tax provision increased $89 million, or 468%, in 2016 as compared to 2015. The increase in the tax provision was primarily the result of the statutory tax effect of higher pre-tax income in 2016 compared to 2015, partially offset by higher tax benefits from property-related timing differences in 2016 compared to 2015. The higher effective tax rate is driven by higher pre-tax earnings in 2016, partially offset by rate impact from property-related timing differences.

The Utility's income tax provision decreased $403 million, or 105%, in 2015 as compared to 2014. This is primarily the result of the statutory tax effect of lower pre-tax income and higher tax benefits from property-related timing differences in 2015 as compared to 2014. The lower effective tax rate in 2015 is the result of lower pre-tax earnings in 2015 and rate impact from property-related timing differences.

The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) [1] | (2.2) | (4.8) | 1.6 |
| Effect of regulatory treatment of fixed asset differences [2] | (23.4) | (33.7) | (14.7) |
| Tax credits | (0.8) | (1.3) | (0.7) |
| Benefit of loss carryback | (1.1) | (1.5) | (0.8) |
| Non-deductible penalties [3] | 0.8 | 4.3 | 0.3 |
| Other, net [4] | (3.5) | (0.2) | 0.4 |
| **Effective tax rate** | **4.8 %** | **(2.2) %** | **21.1 %** |

(1) Includes the effect of state flow-through ratemaking treatment. In 2016 and 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.
(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted only 2016. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.
(3) Primarily represents the effects of non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for the year ended December 31, 2016 and the effects of the Penalty Decision for the year ended December 31, 2015. For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.
(4) In 2016, the amount primarily represents the impact of tax audit settlements.

**Utility Revenues and Costs that did not Impact Earnings**

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs, see below for more detail.

*Cost of Electricity*

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.)

| (in millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Cost of purchased power | $ 4,510 | $ 4,805 | $ 5,266 |
| Fuel used in own generation facilities | 255 | 294 | 349 |
| **Total cost of electricity** | **$ 4,765** | **$ 5,099** | **$ 5,615** |
| Average cost of purchased power per kWh [1] | $ 0.109 | $ 0.100 | $ 0.101 |
| **Total purchased power (in millions of kWh) [2]** | **41,324** | **48,175** | **52,008** |

(1) Cost of purchased power was impacted primarily by a higher percentage of renewable energy resources.
(2) The decrease in purchased power primarily resulted from an increase in generation from the Utility's Diablo Canyon nuclear power plant and its hydroelectric facilities as well as lower electric customer demand.

The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

*Cost of Natural Gas*

The Utility's cost of natural gas includes the costs of procurement, storage and transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

| (in millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Cost of natural gas sold | $ 481 | $ 518 | $ 813 |
| Transportation cost of natural gas sold | 134 | 145 | 141 |
| **Total cost of natural gas** | **$ 615** | **$ 663** | **$ 954** |
| Average cost per Mcf of natural gas sold | $ 2.45 | $ 2.74 | $ 4.37 |
| **Total natural gas sold (in millions of Mcf)** | **196** | **189** | **186** |

*Operating and Maintenance Expenses*

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2016, 2015, and 2014, no material amounts were incurred above authorized amounts.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its cost of capital. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock. (See "Ratemaking Mechanisms" in Item 1.) The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and issuances and repayments under its revolving credit facility and commercial paper program. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability positions. (See Notes 9 and 13 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue between $400 million and $600 million in common stock during 2017, primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by the timing and outcome of unrecoverable pipeline-related expenses and by fines, penalties and claims that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below. Common stock issuances by PG&E Corporation to fund these needs could have a material dilutive impact on PG&E Corporation's EPS.

**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that, prior to October 2016, primarily consisted of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code. In October 2016, the Utility received approval from the bankruptcy court to release the remaining $161 million of cash held in escrow to unrestricted cash for use by the Utility. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**Financial Resources**

***Debt and Equity Financings***

The Utility issued $1.0 billion in long-term debt and $500 million in short-term debt during the year ended December 31, 2016. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

During 2016, PG&E Corporation sold 2.6 million shares of its common stock under the February 2015 equity distribution agreement for cash proceeds of $149 million, net of commissions paid of $1.3 million. As of December 31, 2016, the remaining gross sales available under this agreement were $275 million.

In August 2016, PG&E Corporation sold 4.9 million shares of its common stock in an underwritten public offering for net cash proceeds of $309 million.

In addition, during 2016, PG&E Corporation sold 7.4 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $364 million.

The proceeds from equity issuances were used for general corporate purposes, including the contribution of equity to the Utility. For the year ended December 31, 2016, PG&E Corporation made equity contributions to the Utility of $835 million. Additionally, PG&E Corporation and the Utility expect to continue to issue long-term and short-term debt for general corporate purposes and to maintain the CPUC-authorized capital structure during 2017.

***Revolving Credit Facilities and Commercial Paper Programs***

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021. At December 31, 2016, PG&E Corporation and the Utility had $300 million and $1.9 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. For the year ended December 31, 2016, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $84 million and $837 million, and a maximum outstanding balance of $176 million and $1.4 billion, respectively. At December 31, 2016, the Utility had an outstanding commercial paper balance of $1.0 billion and PG&E Corporation did not have any commercial paper outstanding. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At December 31, 2016, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51% and 50%, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At December 31, 2016, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

**Dividends**

In May 2016, the Board of Directors of PG&E Corporation and the Utility each adopted a new target dividend payout ratio range of 55% to 65% of earnings, with a target to reach a payout ratio of approximately 60% by 2019. Each Board of Directors retains authority to change the respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

***PG&E Corporation***

For the first quarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. In May 2016, the Board of Directors of PG&E Corporation declared a new quarterly common stock dividend of $0.49 per share. As a result, for each of the second, third and fourth quarters of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share. In 2016, total dividends were $1.925 per share. For each of the quarters in 2015 and 2014, the Board of Directors of PG&E Corporation declared common stock dividends of $0.455 per share, for annual dividends of $1.82 per share. Dividends paid to common shareholders by PG&E Corporation were $921 million in 2016, $856 million in 2015, and $828 million in 2014. In December 2016, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.49 per share, totaling $248 million, of which approximately $243 million was paid on January 15, 2017 to shareholders of record on December 30, 2016.

***Utility***

For the first quarter of 2016, the Board of Directors of the Utility declared a common stock dividend of $179 million to PG&E Corporation. For each of the second, third and fourth quarters of 2016, the Board of Directors of the Utility declared common stock dividends of $244 million to PG&E Corporation. In 2016, total dividends paid by the Utility to PG&E Corporation were $911 million. For each of the quarters in 2015 and 2014, the Board of Directors of the Utility declared common stock dividends of $179 million to PG&E Corporation for annual dividends paid of $716 million in 2015 and 2014. In addition, the Utility paid $14 million of dividends on preferred stock in each of 2016, 2015, and 2014. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends. In December 2016, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on February 15, 2017, to shareholders of record on January 31, 2017.

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2016** | **2015** | **2014** |
| Net cash provided by operating activities | $ 4,344 | $ 3,747 | $ 3,632 |
| Net cash used in investing activities | (5,526) | (5,211) | (4,799) |
| Net cash provided by financing activities | 1,194 | 1,468 | 1,157 |
| **Net change in cash and cash equivalents** | **$ 12** | **$ 4** | **$ (10)** |

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During 2016, net cash provided by operating activities increased by $597 million compared to 2015. This increase was partially due to the Utility receiving an additional $170 million in tax refunds in 2016 than in 2015. The remaining increase was primarily due to fluctuations in activities within the normal course of business such as timing and amount of customer billings and vendor billings and payments. During 2015, net cash provided by operating activities increased by $115 million compared to 2014. This increase was primarily due to higher base revenue collections authorized in the 2014 GRC and lower purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above), offset by the payment of a $300 million fine to the State General Fund as required by the Penalty Decision.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and outcome of ratemaking proceedings, including the 2017 GRC and the TO rate case, and cost of capital proceeding;
- the timing and amounts of costs that may be incurred in connection with claims associated with Butte fire and the timing and amount of related insurance recoveries, fines or penalties that may be imposed in connection with the ex parte OII or costs in connection with a potential settlement, fines or penalties that may be imposed in connection with other enforcement and litigation matters, costs associated with the terms of probation and monitorship imposed in the sentencing phase of the federal criminal trial, and potential remedial and other measures that could be imposed on the Utility in connection with the DOI debarment proceeding (see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below);
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system;
- the timing and amount of tax payments (including the bonus depreciation), tax refunds, net collateral payments, and interest payments, as well as changes in tax regulations that could be adopted by Congress as a result of the new federal administration and other proposals; and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

***Investing Activities***

Net cash used in investing activities increased by $315 million during 2016 as compared to 2015 primarily due to an increase of approximately $440 million in capital expenditures, partially offset by an increase in restricted cash released from escrow by approximately $160 million. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) Net cash used in investing activities increased by $412 million during 2015 as compared to 2014 primarily due to an increase of $340 million in capital expenditures and an increase in net purchases of nuclear decommissioning trust investments in 2015 as compared to net proceeds associated with sales of nuclear decommissioning trust investments in 2014.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $6.0 billion in capital expenditures in each of the years 2017, 2018, and 2019.

***Financing Activities***

During 2016, net cash provided by financing activities decreased by $274 million as compared to 2015. During 2015, net cash provided by financing activities increased by $311 million as compared to 2014. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

## CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2016:

| (in millions) | Payment due by period: Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years | Total |
|---|---|---|---|---|---|
| **Utility** | | | | | |
| Long-term debt [1]: | $ 1,495 | $ 2,408 | $ 3,328 | $ 22,452 | $ 29,683 |
| Purchase obligations [2]: | | | | | |
| Power purchase agreements: | 3,417 | 6,175 | 5,844 | 29,506 | 44,942 |
| Natural gas supply, transportation, and storage | 536 | 329 | 241 | 455 | 1,561 |
| Nuclear fuel agreements | 97 | 188 | 179 | 136 | 600 |
| Pension and other benefits [3] | 388 | 776 | 776 | 388 | 2,328 |
| Operating leases [2] | 44 | 80 | 75 | 168 | 367 |
| Preferred dividends [4] | 14 | 28 | 28 | - | 70 |
| **PG&E Corporation** | | | | | |
| Long-term debt [1]: | 8 | 362 | - | - | 370 |
| **Total Contractual Commitments** | **$ 5,999** | **$ 10,346** | **$ 10,471** | **$ 53,105** | **$ 79,921** |

[1] Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2016 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)
[2] See "Purchase Commitments" and "Other Commitments" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.
[3] See Note 11 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.
[4] Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

The contractual commitments table above excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 8 of the Notes to the Consolidated Financial Statements in Item 8.

### Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) in Item 8.

## ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results.

### *Butte Fire Litigation*

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation

management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling cases. The next case management conference is scheduled for March 2, 2017.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes it was not negligent; however, there can be no assurance that a court or jury would agree with the Utility. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and other damages that the Utility could be liable for under the theories of inverse condemnation and/or negligence.

The Utility believes that it is reasonably possible that it will incur losses related to Butte fire claims in excess of $750 million accrued through December 31, 2016 but is currently unable to reasonably estimate the upper end of the range of losses because it is still in an early stage of the evaluation of claims, the mediation and settlement process, and discovery. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of approximately $900 million. Such insurance coverage is subject to the terms and limitations of the applicable policies and may not be sufficient to cover the Utility's ultimate liability.

The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. The Utility has recorded $625 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility is pursuing coverage under the insurance policies of its two vegetation management contractors, including under policies where the Utility is listed as an additional insured. Recoveries of any amounts under these policies are uncertain. If the ultimate liability exceeds the amounts recovered through insurance, the Utility would expect to seek authorization from the CPUC and the FERC to recover any excess amounts from customers. The Utility is unable to predict the timing or outcome of any such proceeding, or the timing of recovery from customers, if any. The resolution of claims, any future regulatory proceeding, and the recoveries from other potentially responsible parties and customers could extend over a number of years. (For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

***Department of Interior Inquiry***

In September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the San Bruno explosion and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. The Utility filed its initial response on November 2, 2015 to demonstrate that it is a "presently responsible" contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate. On April 8, 2016, the Utility received a series of follow-up questions from the DOI regarding its November 2015 submission. On November 21, 2016, the Utility provided the DOI with a supplemental submission in which it addressed the DOI's April 8, 2016 questions. The Utility continues to fully cooperate with the DOI.

As a result of the August 9, 2016 jury's verdict in the federal criminal trial, the Utility updated its registration on the federal government's System for Award Management (SAM), a federal procurement database, to reflect the verdict. Under federal law, the government may not enter into a contract with any corporation that was convicted of a felony criminal violation under any federal law within the preceding 24 months, where the awarding agency is aware of the conviction, unless an agency has considered suspension or debarment of the corporation and made a determination that this action is not necessary to protect the interests of the government.

On December 21, 2016, the Utility and the DOI entered into an interim administrative agreement that reflects the DOI's determination that the Utility remains eligible to contract with federal government agencies while the DOI determines whether any further action is necessary to protect federal government's business interests. The agreement will be effective until superseded by an amended agreement or determination. The agreement also provides that the DOI is still conducting a review to determine whether the Utility has an effective compliance and ethics program and that the DOI is required to use its best efforts to complete its review before the end of 2017. If the DOI determines that the Utility's program is not generally effective in preventing and detecting criminal conduct, the Utility may be required to enter into an amended administrative agreement and implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third party monitor(s).

The Utility could incur material costs, not recoverable through rates, to implement remedial and other measures that could be imposed, the amount of which the Utility is currently unable to estimate.

***Litigation Related to the San Bruno Accident and Natural Gas Spending***

As of December 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the *San Bruno Fire Derivative Cases* and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are *Tellardin v. Anthony F. Earley, Jr.,. et al., Iron Workers Mid-South Pension Fund v. Johns, et al.,* and *Bushkin v. Rambo et al*.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated *San Bruno Fire Derivative Cases* pending conclusion of the federal criminal proceedings against the Utility. On November 16, 2016, counsel in the four consolidated *San Bruno Fire Derivative* cases, as well as counsel in the *Tellardin* action, appeared for a status conference in the San Mateo Superior Court. The court reaffirmed that all proceedings in these actions were stayed until the conclusion of the Utility's federal criminal proceeding, at which point they were directed to meet and confer and report back to the court. The parties completed a mediation session on December 8-9, 2016 and continue discussions about the potential resolution of the matter. These actions remain stayed.

*Bushkin v. Rambo et al*., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit *Iron Workers Mid-South Pension Fund v. Johns, et al*., discussed below. The plaintiff in the *Bushkin* lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the *Bushkin* plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the *San Bruno Fire Derivative Cases* has been lifted, or, in the alternative, a demurrer asking the court to dismiss plaintiff's petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation's motion, and indicated that plaintiff's petition was stayed pending resolution of the criminal matter against the Utility. On January 13, 2017, the parties submitted a joint case management statement advising the court that, because the Utility had not yet been sentenced, the case should remain stayed until at least March 10, 2017, when the parties will advise the court of further developments. While the Utility was sentenced in the federal criminal proceeding on January 26, 2017, this matter remains stayed until at least March 10, 2017.

The *Iron Workers* action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the *San Bruno Fire Derivative Cases*. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court's request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the *San Bruno Fire Derivative Cases*. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the

stay pending the resolution of the federal criminal proceeding against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017. This matter remains stayed until at least March 15, 2017.

For more information about the federal criminal proceeding, see Note 13 of the Notes to the Consolidated Financial Statements and Item 3 Legal Proceedings.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

## REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC, and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

### 2017 General Rate Case

On September 1, 2015, the Utility filed its 2017 GRC application with the CPUC. On August 3, 2016, the Utility, together with ORA, TURN, and 12 other intervening parties filed a motion with the CPUC seeking approval of a settlement agreement that resolves nearly all of the issues raised by the parties in the Utility's 2017 GRC. All parties who filed testimony in the case joined the settlement agreement, which was the subject of a one-day workshop overseen by the assigned commissioner and ALJ. The settlement agreement will ultimately be considered by the full commission. In the GRC proceeding, the CPUC will determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2017 through 2019 or 2020 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. (The Utility's revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.)

*Revenue Requirements and Attrition Year Revenues*

The settlement agreement proposed that the Utility's 2016 authorized revenue requirement of $7.9 billion be increased by $88 million, effective January 1, 2017. The settlement agreement further proposed an increase to the authorized 2017 revenues of $444 million in 2018 and an additional increase of $361 million in 2019, as shown in the table below.

The settlement agreement identified two contested issues. First, the parties were unable to agree on whether there should be a third post-test year or "attrition" year for this GRC cycle. ORA and the Utility recommend a third post-test year for this cycle that would provide for an additional increase of $361 million in 2020. TURN and certain other settling parties oppose the third post-test year. The other contested issue concerns whether the Utility should be authorized to establish a new balancing account for costs arising from the CPUC's rulemaking on natural gas leak abatement. The Utility and certain settling parties support the balancing account. TURN and certain other settling parties do not. ORA does not oppose it. Interested parties filed comments and reply comments on the contested issues and these issues were also discussed at a one-day workshop on August 30, 2016.

The table below summarizes the differences between the amount of revenue requirement increases included in the Utility's request, as updated in the Utility's supplemental testimony filed on February 22, 2016 and its May 27, 2016 rebuttal testimony, and the amount proposed in the settlement agreement:

| Year | Increase Requested in GRC Application (in millions) | Increase Proposed in Settlement Agreement (in millions) | Difference[1] (Decrease from GRC Application) (in millions) |
|---|---|---|---|
| 2017 | $ 319 | $ 88 | $ (231) |
| 2018 | 467 | 444 | (23) |
| 2019 | 368 | 361 | (7) |
| 2020[2] | N/A | 361 | N/A |

[1] Rounded for presentation purposes.
[2] Whether or not revenues should be authorized for 2020 is a contested issue.

The following table shows the difference between the Utility's requested increases in 2017 revenue requirements by line of business and the amounts proposed in the settlement agreement:

| (in millions) Line of Business: | Increase Requested in GRC Application | | | Increase/(Decrease) Proposed in Settlement Agreement | | | Difference[1] (Decrease from GRC Application) |
|---|---|---|---|---|---|---|---|
| Electric distribution | $ 67 | 1.6 | % | $ (62) | (1.5) | % | $ (128) |
| Gas distribution | 59 | 3.4 | | (3) | (0.2) | | (62) |
| Electric generation | 193 | 9.9 | | 153 | 7.8 | | (40) |
| **2017 revenue requirement increases** | **$ 319** | **4.0** | **%** | **$ 88** | **1.1** | **%** | **$ (231)** |

[1] Rounded for presentation purposes.

The following table shows the differences, by line of business and cost category, between the amount of revenue requirements included in the GRC application and the amount proposed in the settlement agreement, as well as the differences between the 2016 authorized revenue requirements and (i) the GRC application and (ii) the amounts proposed in the settlement agreement:

| (in millions) [1]<br>**Line of Business:** | **Amounts Requested in 2017 GRC Application** | **Amounts Proposed in Settlement Agreement** | **Difference (Decrease)** | **Increase/ (Decrease) 2016 vs. 2017 Application** | **Increase/ (Decrease) 2016 vs. Agreement** |
|---|---|---|---|---|---|
| Electric distribution | $ 4,279 | $ 4,151 | $ (128) | $ 67 | $ (62) |
| Gas distribution | 1,801 | 1,738 | (62) | 59 | (3) |
| Electric generation | 2,155 | 2,115 | (40) | 193 | 153 |
| **Total revenue requirements** | **$ 8,235** | **$ 8,004** | **$ (231)** | **$ 319** | **$ 88** |
| | | | | | |
| **Cost Category:**<br>(in millions) [1] | | | | | |
| Operations and maintenance | $ 1,825 | $ 1,794 | $ (31) | 161 | 131 |
| Customer services | 361 | 334 | (27) | 42 | 15 |
| Administrative and general | 975 | 912 | (62) | (36) | (99) |
| Less: Revenue credits | (140) | (152) | (12) | (9) | (21) |
| Franchise fees, taxes other than income, and other adjustments | 184 | 170 | (14) | 146 | 132 |
| Depreciation (including costs of asset removal), return, and income taxes | 5,030 | 4,946 | (84) | 15 | (70) |
| **Total revenue requirements** | **$ 8,235** | **$ 8,004** | **$ (231)** | **$ 319** | **$ 88** |

[1] Rounded for presentation purposes.

The settlement agreement proposed reductions in the following areas forecast in the GRC application. For gas distribution, reductions are proposed for corrosion control, leak management, gas operations technology, and new business. For electric distribution, reductions are proposed for overhead maintenance, capacity, technology, mapping and records, reliability, substation management, new business, and undergrounding work. For electric distribution, the capital-related reductions are offset in part by increases in the replacement and installation of additional units in specific asset areas. For electric generation, the settlement agreement proposed to move costs related to Diablo Canyon seismic studies from the GRC to the Utility's Energy Resource Recovery Account proceeding. Proposed reductions in the customer service area largely relate to the removal of certain costs from the forecast related to residential rate reform implementation. Some of these costs would be recoverable through the existing Residential Rates Reform Memorandum Account, and the Utility could seek recovery of the remaining costs in a future filing with the CPUC. Additionally, a number of company-wide reductions, including reductions to the Short-Term Incentive Plan and certain employee benefits, are proposed in the settlement agreement.

*Balancing Accounts*

The settlement agreement proposes to retain certain existing balancing accounts, including the Tax Act Memo Account that was first established following the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, and to eliminate certain memorandum and balancing accounts that are no longer necessary. In addition to the contested balancing account for natural gas leak abatement mitigation costs, the settlement agreement proposes one new tax-related memorandum account to track the impact on the revenue requirement from certain types of changes in tax laws or regulations.

*Capital Additions and Rate Base*

The settlement agreement proposes capital expenditures of $3.9 billion for 2017 for the portions of the Utility's business addressed in the GRC. Proposed capital expenditures are lower than the amount included in the GRC application of $4.0 billion for 2017, consistent with the provisions of the settlement agreement. While the settlement agreement proposes overall revenue requirement increases for 2018 and 2019, it does not specify capital expenditures for those years. At the August 30, 2016 workshop, the Utility estimated authorized capital expenditures of $3.6 billion for 2018 and $3.5 billion for 2019, based on a calculation method that is subject to CPUC approval, as compared to its request of approximately $4.0 billion each year. The Utility is unable to predict if the CPUC will approve its proposed calculation method.

The settlement agreement proposes a 2017 weighted average rate base of $24.3 billion for the portions of the Utility's business reviewed in the GRC, compared with the Utility's request of $24.5 billion. The $200 million difference is primarily due to the lower level of capital expenditures agreed to in the settlement. At the August 30, 2016 workshop, the Utility also estimated a weighted average rate base of $25.4 billion for 2018 and $26.3 billion for 2019, compared with the Utility's request of $25.7 billion and $26.9 billion, respectively.

Evidentiary hearings were held on September 1, 2016. A workshop was held on January 11, 2017 to further explore the three-year versus four-year rate case cycle. Under the current schedule, a final CPUC decision is expected to be issued in the first half of 2017. On March 17, 2016, the CPUC issued a decision to allow the authorized revenue requirement changes to become effective on January 1, 2017, even if the final decision is issued after that date.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the settlement agreement.

**2015 Gas Transmission and Storage Rate Case**

On June 23, 2016, the CPUC approved a final decision in phase one of the Utility's 2015 GT&S rate case. The decision adopts the revenue requirements that the Utility is authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period (see table below). The decision authorizes the Utility to collect, over a 36-month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. Accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. As a result, the Utility will complete recording $102 million of the retroactive revenue requirement increase in the first quarter of 2017.

The phase one decision excludes from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallows $120 million of that amount and orders that the remaining $576 million be subject to a third party audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also establishes various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way capital balancing accounts. In the second quarter of 2016, the Utility incurred charges of $190 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This includes $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. The Utility took an additional charge of $29 million in the fourth quarter of 2016 related to 2015 through 2018 capital expenditures that are forecasted to exceed authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011through 2014 capital spending.

The phase one decision denies the Utility's request for full balancing account treatment for recovery of authorized transportation and storage revenue requirements for non-core customers, and instead continues the revenue sharing mechanism authorized in the 2011 GT&S rate case that subjects a portion of the Utility's transportation and storage revenue requirement to market risk.

The phase one decision also authorizes the Utility's request for cost recovery of up to $157 million for the construction of Line 407, a 25.5 mile, 30-inch pipeline in the Sacramento Valley expected to be built during this rate case period. The authorized revenue requirements will begin when Line 407 becomes operational. The decision also authorizes the Utility to track costs exceeding $157 million in a memorandum account. A reasonableness review of all costs for Line 407 will take place in the next GT&S rate case.

On August 1, 2016, TURN, ORA, and Indicated Shippers filed an application for rehearing of the phase one decision. The application indicates that the decision contains language suggesting that the authorized revenue requirement is to comply with new federal and state safety mandates and should be removed from the final decision, allows recovery of shareholder costs in rates, and improperly sequences the calculation of the San Bruno Penalty and the ex parte disallowance. The Utility filed a response on

August 16, 2016. The Utility cannot predict when or if the CPUC will grant the rehearing or if it will adopt the parties' recommendations.

On December 1, 2016, the CPUC approved a final decision in phase two of the Utility's 2015 GT&S rate case, regarding the $850 million penalty assessed in the Penalty Decision. The final phase two decision applies $689 million of the $850 million penalty (81 percent) to capital expenditures and the remaining $161 million (19 percent) to expenses, and then reduces the 2015 revenue requirement by $72 million for the five-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding ($57 million of the $72 million total ex parte disallowance was recognized in 2016 and the remaining $15 million will be recognized in the first quarter of 2017). The final decision also approves the Utility's list of programs which meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty.

The following table shows the revenue requirement amounts adopted in the Utility's 2015 GT&S rate case including adjustments for the $850 million Penalty Decision disallowance and the ex parte disallowance:

| (in millions) | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|
| Revenue Requirement Before Adjustments | $ 1,046 | $ 1,110 | $ 1,220 | $ 1,324 |
| San Bruno Penalty Expense Allocation | (161) | | | |
| San Bruno Penalty Capital Revenue Requirement Allocation | 5 | (47) | (93) | (93) |
| Other Expense Adjustments | (3) | (2) | (2) | (1) |
| Adjusted Ex Parte Penalty | (72) | | | |
| Final Phase Two Revenue Requirement | $ 815 | $ 1,061 | $ 1,125 | $ 1,230 |

The final phase two decision adopts total weighted average rate base of $2.8 billion in 2015, $2.8 billion in 2016, $3.0 billion in 2017, and $3.5 billion in 2018. The final phase two decision reduces rate base by the full amount of the disallowed capital expenditures but does not remove the associated deferred taxes, which the Utility believes creates a normalization violation. In the final decision, the CPUC authorizes the Utility to establish a Tax Normalization Memorandum Account to track relevant costs and clarifies that it does not intend the rate base offset or the penalty generally, to create tax timing differences. The final decision also affirms the CPUC's intention to comply with normalization rules and to avoid the potential adverse consequences of a finding of a normalization violation by the IRS. Pursuant to the final phase two decision, on February 6, 2017, the Utility submitted an advice letter to the CPUC to provide 30 days advance notice of the Utility's request to the IRS for a private letter ruling to determine whether the adopted rate base offset complies with IRS normalization rules. The final decision authorizes the Utility to subsequently seek an appropriate adjustment to its revenue requirements and rate base if the IRS finds a normalization violation.

On January 4, 2017, TURN, ORA and Indicated Shippers filed an application for rehearing of the phase two decision. Specifically, the application argues that the decision inappropriately sequenced the San Bruno Penalty and the ex parte ratemaking disallowance. The Utility filed a response on January 19, 2017. The Utility cannot predict when or if the CPUC will grant the rehearing.

With the addition of a third attrition year, the Utility's next GT&S cycle will begin in 2019. The decision requires the Utility to file its next GT&S application in 2017.

**FERC Transmission Owner Rate Cases**

On July 29, 2015, the Utility requested a 2016 retail electric transmission revenue requirement of $1.515 billion, a $314 million increase over the previous year's authorized revenue requirement of $1.201 billion. The Utility's proposed rates went into effect on March 1, 2016, subject to refund, and pending a final decision by the FERC. On September 1, 2016, the Utility and other settling parties (including the CPUC) filed a motion at the FERC for approval of a settlement proposing that the Utility's 2016 retail electric transmission revenue requirement be set at $1.331 billion, a $130 million increase over the previous year's authorized revenue requirement. The Utility also filed a motion on September 1, 2016, requesting the implementation of interim rates, which was an agreed upon term of the settlement. The motion was granted and, as a result, the interim rates became effective for wholesale customers on September 1, 2016 and for retail customers on October 1, 2016. The FERC approved the settlement on November 17, 2016.

On July 29, 2016, the Utility filed a rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of $1.718 billion, a $387 million increase over the 2016 revenue requirement of $1.331 billion. The forecasted network transmission rate base for 2017 is $6.7 billion. The Utility is also seeking a return on equity of 10.9% which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted that it will make investments of $1.296 billion in 2017 in various capital projects.

On September 30, 2016, the FERC issued an order accepting the Utility's July 2016 filing and set it for settlement negotiations. The order set an effective date for rates of March 1, 2017, and made the rates subject to hearing and refund. The next settlement conference is scheduled for March 16 and March 17, 2017.

**CPUC Cost of Capital**

On February 6, 2017, the Utility and other California IOUs entered into a MOU with the CPUC, ORA, and TURN to extend the next cost of capital application filing deadline two years to April 22, 2019 for the year 2020. To implement the MOU, on February 7, 2016, the IOUs, ORA, and TURN filed with the CPUC a petition for modification of prior CPUC decisions addressing the cost of capital. If the petition for modification is approved as submitted it would reduce the Utility's ROE from 10.40% to 10.25% and reset the Utility's authorized cost of long-term debt and preferred stock beginning January 1, 2018. The long-term debt cost reset will reflect actual embedded costs as of the end of August 2017 and forecasted interest rates for the new long-term debt scheduled to be issued for the remainder of 2017 and all of 2018. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity would remain unchanged.

If and once the petition for modification is granted by the CPUC, each IOU will submit to the CPUC in September 2017 its respective updated cost of capital and corresponding revenue requirement impacts with an effective date of January 1, 2018. While the actual changes to the Utility's revenue requirement resulting from the petition for modification will not be known until the Utility's filing in September 2017, the Utility estimates that its annual revenue requirement will be reduced by approximately $100 million, beginning in 2018. These estimates are based on current and forecasted market interest rates. Changes in market interest rates can have material effects on the cost of the Utility's future financings and consequently on the estimated change in annual revenue requirements.

The Utility's cost of capital adjustment mechanism would not operate in 2017 but could operate in 2018 to change the cost of capital for 2019. If the mechanism is activated for 2019, the Utility's cost of capital, including its new ROE of 10.25%, will be adjusted according to the existing terms of the mechanism. Concurrently with the petition for modification, the Utility and other California IOUs sent a letter to the executive director of the CPUC requesting that the existing April 2017 filing due date for the 2018 cost of capital be deferred while the CPUC is considering the petition for modification. On February 13, 2017, the executive director of the CPUC granted the request. As extended, the Utility and the other California IOUs would file their next cost of capital applications 60 days after the effective date of the CPUC decision on the petition for modification, or April 20, 2017, whichever is later, if the CPUC does not grant the petition for modification. The Utility expects that the CPUC may issue a decision in the first half of 2017.

**Diablo Canyon Nuclear Power Plant**

*Joint Proposal for Plant Retirement*

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application implements a joint proposal between the Utility and the Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and Alliance for Nuclear Responsibility.

The application and joint proposal include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables. The parties to the joint proposal proposed that the Utility be authorized to procure GHG-free replacement resources in three competitive procurement tranches: in Tranche 1, the Utility would be authorized to obtain 2,000 gross GWh of energy efficiency savings to be implemented over the 2018 to 2024 time period; in Tranche 2, the Utility would be authorized to procure through a solicitation 2,000 GWh of GHG-free energy resources that will commence energy deliveries or add energy efficiency projects to the system in the 2025 to 2030 time period; and in Tranche 3, the Utility would commit to a voluntary 55% RPS beginning in 2031, and would maintain this voluntary commitment through 2045 or until superseded by action of the state legislature or the CPUC. The three tranches of resource procurement in the application and joint proposal are not intended to specify all energy resources that will be needed to ensure the orderly replacement of Diablo Canyon. Instead, the Utility expects that the full solution will be addressed in ongoing CPUC proceedings.

Costs associated with energy efficiency projects or programs in Tranche 1 and Tranche 2 would be recovered through the Utility's electric public purpose program rates as non-bypassable charges, consistent with the existing recovery mechanisms for energy efficiency program costs. GHG-free energy resources costs from Tranche 2 are proposed to be recovered through a non-bypassable cost allocation mechanism called the Clean California Charge that (1) equitably allocates costs and benefits, such as RPS or Resource Adequacy credits, associated with the procurement among responsible load-serving entities, and (2) determines the net capacity costs of such procurement consistent with the methodology for the allocation of net capacity costs laid out by the CPUC. Costs associated with procurement for Tranche 3 would be recovered through a separate renewable non-bypassable charge.

The application seeks confirmation from the CPUC that the Utility's full investment in Diablo Canyon and authorized rate of return will be recovered in rates by the time the facility ceases operations. Additionally, the Utility requests that the CPUC pre-approve the recovery of certain costs related to the closure of the Diablo Canyon. These include the non-bypassable cost allocation mechanism for procurement of GHG-free energy and the recovery of $1.3 billion for administration and acquisition of the new Tranche 1 energy efficiency procurement as authorized energy efficiency funding, subject to return of all unspent funds; the recovery of employee retention and retraining and development programs to continue safe and efficient operation of Diablo Canyon through the end of its license periods, estimated at approximately $360 million; and a community mitigation program to compensate San Luis Obispo County for the decline in local economic stimulus provided by Diablo Canyon through a transition period ending in 2025, estimated at $85 million. The Utility also seeks cost recovery of approximately $50 million in costs related to the federal and state Diablo Canyon license renewal process.

More than 40 parties have submitted responses and protests to the Utility's application. A prehearing conference on the application was held on October 6, 2016 and public participation hearings were held in San Luis Obispo on October 20, 2016. On November 18, 2016, a scoping memo was issued that set the schedule and determined that land issues would be out of the scope of this proceeding. In December 2016, the Utility filed with the CPUC the community impact mitigation program settlement agreement of $85 million, compared to $50 million included in the original joint proposal filed on August 11, 2016. Intervenor testimonies were submitted to the CPUC in January 2017. Several intervenors indicated their support to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025. Several parties argued, however, that a component of the employee retention program and community impact mitigation program be funded by shareholders. Several intervenors also submitted proposals for modifications to certain aspects of the three GHG-free replacement tranches. Several parties recommended that the license renewal project cost recovery request be rejected and/or be paid for by both customers and shareholders. There were no direct challenges to the Diablo Canyon remaining net book value cost recovery proposal. Rebuttal testimony and comments on the community impact mitigation program settlement agreement are scheduled to be submitted to the CPUC on March 17, 2017 and evidentiary hearings are scheduled to take place in April 2017. Opening and reply briefs are due on May 26, 2017 and June 9, 2017, respectively. The Utility expects that a final decision will be issued by the end of 2017. Upon CPUC approval of the application and such approval becoming final and non-appealable, the Utility will withdraw its license renewal application currently pending before the NRC. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the application.

*California State Lands Commission Lands Lease*

On June 28, 2016, California State Lands Commission approved a new lands lease for the intake and discharge structures at Diablo Canyon to run concurrently with Diablo Canyon's current operating licenses, until Diablo Canyon Unit 2 ceases operations in August 2025. The Utility believes that the approval of the new lease will ensure sufficient time for the Utility to identify and bring online a portfolio of GHG-free replacement resources. The Utility will submit a future lease extension request to address the period of time required for plant decommissioning, which under NRC regulations can take as long as 20 years. On August 28, 2016, the World Business Academy (WBA) filed a writ in the Los Angeles Superior Court. WBA asserts that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act. If the petitioner prevails in its challenge, the State Lands Commission could be required to perform an environmental review of the new lands lease. The court has set a trial date of July 11, 2017, with the petitioner's opening brief due February 27, 2017, opposition briefs due April 24, 2017, and reply briefs due May 22, 2017.

*Asset Retirement Obligations*

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion, for a total estimated cost of $4.8 billion, due to increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

While the NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the joint proposal's employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program described above. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study to the CPUC by mid-2019.

On July 15, 2016, the assigned CPUC commissioner and ALJ issued a scoping memo for the Utility's 2015 NDCTP and excluded from the scope of the proceeding the issue on whether the Utility should be required to present additional analysis for a license extension scenario for Diablo Canyon, as a result of the Utility's announcement of its plan to not seek relicensing of Diablo Canyon beyond its current operating authority. The scoping memo also adopts within the scope of the proceeding a reasonableness review of the Utility's estimated updated cost to decommission the Utility's nuclear power plants and of the forecasts of certain expenses and the decommissioning trust funds' rates of return. Evidentiary hearings took place in September 2016 and opening briefs were submitted on October 14, 2016. Intervenor parties proposed several major recommendations including a reduction to the total spent nuclear fuel storage forecast, a reduction to the large component (reactor vessels, steam generators, and other large plant components) removal cost estimate, and a reduction to the waste disposal estimate. Additionally, intervenors asserted that the CPUC should not permit the Utility to increase its Diablo Canyon-related revenue requirement at this time as it has not demonstrated its current estimate is reasonable. Parties also claimed that the Utility has not justified its increase to security costs and decommissioning oversight contractor staff costs. No party challenged the Utility's decommissioning trust funds rates of return or cost escalation assumptions. Reply briefs were submitted on October 31, 2016. Intervenor parties reiterated that the Utility has not justified increases in costs due to large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility confirmed that the testimony and work papers support the cost increases as well as the total estimate to decommission Diablo Canyon.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.5 billion at December 31, 2016, which includes an $818 million adjustment to reflect the increased cost estimates and a $115 million increase resulting from the joint proposal described above, and $2.5 billion at December 31, 2015. These estimates are based on decommissioning cost studies, prepared in accordance with the CPUC requirements. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

As of December 31, 2016, the nuclear decommissioning trust accounts' total fair value was $2.9 billion. Changes in the estimated costs, the timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission.

**CPUC Investigation of the Utility's Safety Culture**

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment. The consultant's work began in the second quarter of 2016.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned commissioner will determine the scope of any next actions in the proceeding. The timing, scope and potential outcome of the investigation are uncertain.

**2014 – 2015 Energy Efficiency Incentive Awards**

On December 15, 2016, the CPUC approved a final 2014 - 2015 Energy Efficiency Incentive Award of $16.3 million, compared to the Utility's request of $19.1 million. The award includes a $5.8 million reduction reflecting the approved settlement agreement related to the rehearing of the 2006 - 2008 customer energy efficiency shareholder incentives. The settlement agreement requires the Utility to reduce future energy efficiency shareholder incentives by $29.1 million, which will be applied in installments of $5.8 million per year for five years, provided that the Utility has sufficient energy efficiency incentive awards to offset that amount. Due to the application of the first offset of $5.8 million, the required future energy efficiency reduction currently corresponds to $23.3 million. If shareholder incentives are insufficient to offset this amount, the offset in the following year will be increased by the shortfall. At its discretion, the Utility may increase the amount of the offset to reduce the remaining offset obligation more quickly. If the amount has not been fully offset at the end of five years, the balance will be credited against future energy efficiency program spending.

**LEGISLATIVE AND REGULATORY INITIATIVES**

The California Legislature and the CPUC have adopted requirements, policies, and decisions to improve and refine gas and electric safety citation programs, implement new state law requirements applicable to natural gas storage facilities, accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, promote customer energy efficiency and demand response programs, and foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. CPUC proceedings related to some of these matters are discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

*Gas and Electric Safety Citation Program*

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day.

On September 29, 2016, the CPUC issued a final decision adopting improvements and refinements to its gas and electric safety citation programs. Specifically, the final decision refines the criteria for the SED to use in determining whether to issue a citation

and the amount of penalty, sets an administrative limit of $8 million per citation issued, makes self-reporting voluntary in both gas and electric programs, adopts detailed criteria for the utilities to use to voluntarily self-report a potential violation, and refines other issues in the programs. The decision also merges the rules applicable to its gas and electric safety citation programs into a single set of rules that replace the previous safety citation programs and adopts non-substantive changes to these programs so that the programs can be similar in structure and process where appropriate.

*Natural Gas Storage Facilities*

On January 6, 2016, the California Governor ordered the DOGGR to issue emergency regulations to require gas storage facility operators throughout California, including the Utility, to comply with new safety and reliability measures, including minimum daily inspection of gas storage well heads (using gas leak detection technology such as infrared imaging), ongoing verification of the mechanical integrity of all gas storage wells, ongoing measurement of annular gas pressure or annular gas flow within wells, regular testing of all safety valves used in wells, establishing minimum and maximum pressure limits for each gas storage facility in the state, and establishing a comprehensive risk management plan that evaluates and prepares for risks at each facility, including corrosion potential of pipes and equipment. On February 5, 2016, the DOGGR adopted the emergency regulations. The Utility implemented the regulations and submitted an Underground Storage Risk and Integrity Management Plan on August 5, 2016 that is pending DOGGR approval.

Additionally, in September 2016, the California Governor signed SB 887 directing DOGGR and CARB to develop permanent regulations for gas storage facility operations in California, which are expected to be finalized in the second half of 2017. The PHMSA has also issued interim final rules effective January 18, 2017 regulating gas storage facilities at the federal level. The Utility may incur significant costs to comply with the new regulations related to (1) the development of a natural gas leak prevention and response program, (2) the development of a plan for corrosion monitoring and evaluation, (3) proactive replacement of equipment at risk of failure, and (4) a review of risk management plans to consider new risk factors. The Utility plans to file an advice letter with the CPUC in the first quarter of 2017 to request a memorandum account to track the future incremental costs associated with implementing the new regulations. Upon approval, a subsequent application would be submitted to the CPUC for recovery of the incremental costs being tracked. The Utility is unable to estimate the timing and outcome of such request.

*New Renewable Energy Targets*

In October 2015, the California Governor signed SB 350 into law, which became effective January 1, 2016. SB 350 increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period and in each three year compliance period thereafter. SB 350 includes increasing interim renewable energy targets for the periods between 2020 and 2030 and continues to include compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets which the Utility expects will continue to be recoverable from customers as “pass-through” costs. The Utility also may be subject to penalties for failure to meet the higher targets.

In December 2016, the CPUC issued the first of a series of decisions to implement the RPS-related provisions of SB 350. The decision addressed compliance periods and procurement quantity requirements. Subsequent rulings and decisions are expected in 2017 to address scope and implementation details.

Additionally, as stated above, the Utility’s application and joint proposal to retire Diablo Canyon include a voluntary increase in the Utility’s target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state’s goal of 50% renewables.

*Electric Distribution Resources Plan*

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility’s plan identifies optimal locations on its electric distribution system for deployment of DERs. The Utility’s proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service.

On January 24, 2017, the CPUC convened a workshop aimed at informing the development of a CPUC framework to evaluate grid-modernization investments. The workshop was attended by the California IOUs, the DER industry, consumer advocates, the DOE, and the CPUC's Energy Division staff. The Energy Division staff is expected to develop a grid modernization investment framework in the first quarter of 2017. Additionally, on February 9, 2017, the CPUC issued a decision approving two out of three of the Utility's proposed field demonstration projects to test various distribution-related services that DERs might provide to the Utility. The Utility in unable to predict when a final CPUC decision approving, disapproving, or modifying the Utility's electric distribution resources plan will be issued.

*Integrated Distributed Energy Resources – Regulatory Incentives Pilot Program*

On April 4, 2016, the assigned CPUC commissioner and ALJ issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective DERs. The ruling assumed that the incentive would take the form of an additional payment to the Utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The ruling also stated that it did not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities.

On September 1, 2016, the assigned CPUC commissioner and ALJ issued an amended scoping memo and ruling that re-categorized all activities in the proceeding as rate-setting, consolidated remaining issues into one phase, and proposed a revised regulatory incentive pilot to test how an earnings opportunity affects DER sourcing. On December 22, 2016, the CPUC issued a final decision in the proceeding which authorizes a pilot to test a regulatory incentive mechanism through which the Utility will earn a 4% pre-tax incentive on annual payments for DERs, as well as test a regulatory process that will allow the Utility to competitively solicit DER services to defer distribution infrastructure. Each utility is required to conduct at least one pilot, but may conduct up to three additional pilots.

*Electric Rate Reform and Net Energy Metering (NEM)*

On July 3, 2015, the CPUC approved a final decision to authorize the California IOUs to gradually flatten their tiered residential electric rate structures to two tiers by January 2019. The decision approved higher minimum bill charges for residential customers and also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential electric customers based on time-of-use rates (known as "default time-of-use rates") unless customers elect otherwise. The Utility also may propose to impose a fixed charge on residential electric customers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge in electric rates.

In January 2016, the CPUC adopted new NEM rules. The new rules became effective for new NEM customers in December 2016, when the Utility reached its NEM cap of 2,409 MW. New NEM customers will be required to pay an interconnection fee, will be charged for energy use on time-of-use rates, and will be required to pay non-bypassable charges to help fund some of the costs of low-income, energy efficiency, and other programs that other customers pay. Unlike the initial NEM tariff, there is no cap on the total capacity of distributed generation that can be installed under the new rules, and there is no size limitation on the projects, so long as projects over 1MW pay actual interconnection costs. On March 7, 2016, the Utility and certain other parties, including TURN and CUE, filed applications for rehearing. The Utility requested that the CPUC vacate its January 2016 decision that the Utility asserts contains legal and factual errors. Many parties argued that the CPUC failed to complete its duties under AB 327, which required the CPUC to evaluate the costs and benefits of NEM. On September 15, 2016, the CPUC voted to deny the applications for rehearing, concluding that good cause had not been established to grant a rehearing and that the NEM decision adopted a successor tariff as required. The CPUC indicated that it may revisit the NEM successor tariff in 2019.

*Electric Vehicle (EV) Infrastructure Development*

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain EV charging stations and the associated infrastructure. On December 15, 2016, the CPUC issued a final decision establishing a three-year EV program of $130 million (approximately $109 million in capital expenditures) to deploy up to 7,500 charging stations. Further deployment of light-duty EV infrastructure will be considered in a second phase of the proceeding.

*Transportation Electrification (TE) Application*

SB 350 orders the CPUC, in consultation with the CARB and the CEC, to direct electrical corporations to file applications for programs and investments to accelerate widespread TE. In September 2016, the CPUC directed the large IOUs to file projects to accelerate TE in the state, including both one-year projects (of up to $20 million total) and two to five-year programs with a requested revenue requirement determined by the utility. On January 20, 2017, the Utility filed its TE application with the CPUC requesting a total of up to $253 million (approximately $211 million in capital expenditures) in program funding over five years (2018 - 2022) primarily related to make-ready infrastructure for TE in medium to heavy-duty sectors. Protests are due March 6, 2017 and a prehearing conference is scheduled for March 16, 2017. The Utility expects a decision to be issued within 12 to 18 months.

**ENVIRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of $CO_2$ and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Item 1A. Risk Factors and "Environmental Regulation" in Item 1.)

**Natural Gas Compressor Station Sites**

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment. At December 31, 2016, $299 million and $135 million was accrued in the Consolidated Balances Sheets for estimated undiscounted remediation costs associated with the Topock site and the Hinkley site, respectively. Costs associated with the Hinkley site are not recovered through rates. (See "Environmental Remediation Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**RISK MANAGEMENT ACTIVITIES**

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e. risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

**Commodity Price Risk**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. (See "2015 Gas Transmission and Storage Rate Case" above.)

The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $7 million and $2 million at December 31, 2016 and 2015, respectively. During 2016, the Utility's approximate high, low, and average values-at-risk were $7 million, $1 million and $4 million, respectively. During 2015, the value-at-risk amounts were $2 million, $1 million and $2 million, respectively. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.)

**Interest Rate Risk**

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2016 and 2015, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be $13 million and $11 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of interest rates.)

**Energy Procurement Credit Risk**

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's energy procurement credit risk exposure to its counterparties:

| (in millions) | Gross Credit Exposure Before Credit Collateral [1] | Credit Collateral | Net Credit Exposure [2] | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| December 31, 2016 | $ 69 | $ (11) | $ 58 | 3 | 39 |
| December 31, 2015 | 64 | $ (11) | $ 53 | 4 | 39 |

[1] Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.
[2] Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

## CRITICAL ACCOUNTING POLICIES

The preparation of the Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates and assumptions. These accounting policies and their key characteristics are outlined below.

### Regulatory Accounting

As a regulated entity, the Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2016, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $9.9 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $7.7 billion.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods presented. If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. If regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on its best estimate; to the extent there is a high degree of uncertainty in the Utility's forecast, it will record a provision based on the lower end of the range of possible losses. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

The Utility recorded charges of $283 million in 2016 for capital spending that was disallowed related to the Penalty Decision. The Utility incurred charges of $219 million in 2016 for capital expenditures that will be disallowed based on the final phase two decision in its 2015 GT&S rate case. Additionally, the Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

### Loss Contingencies

As discussed below, PG&E Corporation and the Utility have recorded material accruals for environmental remediation liabilities and for various enforcement and legal matters, and have recorded insurance receivables for third-party claims.

#### *Environmental Remediation Liabilities*

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former manufactured gas plant sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2016 and 2015, the Utility's accruals for undiscounted gross environmental liabilities were $958 million and $969 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.9 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Enforcement and Litigation Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. Management has made significant estimates and assumptions about accruals related to the Butte fire. At December 31, 2016, the Utility's accrual for the Butte fire was $690 million. Actual results may differ materially from these estimates and assumptions. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

***Insurance Receivable***

The Utility has liability insurance from various insurers, which provides coverage for third party claims. The Utility records insurance recoveries only when a third party claim is recorded and it is deemed probable that a recovery of that claim will occur and the Utility can reasonably estimate the amount or its range. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex judgments about future events. Insurance recoveries are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, including contractual liability insurance policy coverage, advice of legal counsel, past experience with similar events, discussions with insurers and other information and events pertaining to a particular matter. Management has made significant estimates and assumptions about insurance recoveries related to the Butte fire. (See "Enforcement and Litigation Matters" and "Legal and Regulatory Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**Asset Retirement Obligations**

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

To estimate its liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2016, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $4.7 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. If the inflation adjustment or discount rate increased 25 basis points, the result would be an immaterial impact to ARO.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Adjustments to the pension and other benefit obligation are based on the differences between actuarial assumptions and actual plan results. These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2017 is 7.2%, gradually decreasing to the ultimate trend rate of 4.5% in 2025 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 5.3% compares to a ten-year actual return of 7.3%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 696 Aa-grade non-callable bonds at December 31, 2016. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2016 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2016 |
|---|---|---|---|
| Discount rate | (0.50) % | $ 109 | $ 1,319 |
| Rate of return on plan assets | (0.50) % | 68 | - |
| Rate of increase in compensation | 0.50 % | 59 | 306 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2016 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2016 |
|---|---|---|---|
| Health care cost trend rate | 0.50 % | $ 4 | $ 58 |
| Discount rate | (0.50) % | 4 | 134 |
| Rate of return on plan assets | (0.50) % | 10 | - |

## NEW ACCOUNTING PRONOUNCEMENTS

See Note 2 of the Notes to the Consolidated Financial Statements.

## FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this 2016 Form 10-K. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the Butte fire litigation, and whether the Utility's insurance is sufficient to cover the Utility's liability resulting therefrom or whether insurance is otherwise available; and whether additional investigations and proceedings in connection with the Butte fire will be opened;

- the timing and outcomes of the 2017 GRC, TO rate case, cost of capital proceeding, and other ratemaking and regulatory proceedings;

- the terms of probation and the monitorship imposed in the sentencing phase of the Utility's federal criminal trial on January 26, 2017, the timing and outcomes of the debarment proceeding and potential remedial and other measures that could be imposed on the Utility as a result of that proceeding, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the timing and outcomes of the CPUC's investigation of communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, or of a potential settlement, and of the U.S. Attorney's Office in San Francisco and the California Attorney General's office investigations in connection with communications between the Utility's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper

communications, and the extent to which such matters negatively affect the final decisions to be issued in the Utility's ratemaking proceedings;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the Utility's conviction in the federal criminal trial, the state and federal investigations of natural gas incidents, matters relating to the criminal federal trial, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- whether the Utility can control its costs within the authorized levels of spending, and successfully implement a streamlined organizational structure and achieve project savings, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- the timing and outcome of the complaint filed by the CPUC and certain other parties with the FERC on February 2, 2017; the complaint requests that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the California ISO's Transmission Planning Process in order to allow for participation and input from interested parties. The planning process that may result from come out of the proceeding may impact the scope and timing of capital transmission projects that the Utility will execute in the future;

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;

- the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

- the outcomes of the SED's investigations of potential violations identified through audits, investigations, or self-reports including in connection with the Utility's February 2017 self-report related to its customer service representatives' drug and alcohol testing program;

- the outcome of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities, inspection and maintenance practices, customer billing and privacy, and physical and cyber security, environmental laws and regulations;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of maintenance costs of the Utility electric transmission facilities;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon; whether the CPUC approves the joint proposal that will phase out the Utility's Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether the Utility obtains the approvals required to withdraw its NRC application to renew the two Diablo Canyon operating licenses; whether the State Lands Commission could be required to perform an environmental review of the new lands lease as a result of the WBA assertion that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act; and whether the Utility will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;

- whether the Utility is successful in ensuring physical security of its critical assets and whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing,

financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility and its third party vendors and contractors (who host, maintain, modify and update some of the Utility's systems) are able to protect the Utility's operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's information technology and operating systems;

- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and sufficient to cover the Utility's liability;

- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, electric vehicles, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;

- the impact of the SB 887 directing DOGGR and CARB to develop permanent regulations for gas storage facility operations in California to comply with new safety and reliability measures, as well the impact of the PHMSA rules effective January 18, 2017 regulating gas storage facilities at the federal level;

- whether the Utility's climate change adaptation strategies are successful;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing for CCAs;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose their investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the jury's verdict in the federal criminal trial of the Utility and its possible conviction, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the impact of the corporate tax reform considered by the new federal administration and the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;

- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the new federal administration; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see Item. 1A. Risk Factors above and our detailed discussion of these matters contained elsewhere in MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in MD&A in Item 7 and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Operating Revenues** | | | |
| Electric | $ 13,864 | $ 13,657 | $ 13,658 |
| Natural gas | 3,802 | 3,176 | 3,432 |
| **Total operating revenues** | **17,666** | **16,833** | **17,090** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,765 | 5,099 | 5,615 |
| Cost of natural gas | 615 | 663 | 954 |
| Operating and maintenance | 7,354 | 6,951 | 5,638 |
| Depreciation, amortization, and decommissioning | 2,755 | 2,612 | 2,433 |
| **Total operating expenses** | **15,489** | **15,325** | **14,640** |
| **Operating Income** | 2,177 | 1,508 | 2,450 |
| Interest income | 23 | 9 | 9 |
| Interest expense | (829) | (773) | (734) |
| Other income, net | 91 | 117 | 70 |
| **Income Before Income Taxes** | **1,462** | **861** | **1,795** |
| Income tax provision (benefit) | 55 | (27) | 345 |
| **Net Income** | **1,407** | **888** | **1,450** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 1,393** | **$ 874** | **$ 1,436** |
| **Weighted Average Common Shares Outstanding, Basic** | **499** | **484** | **468** |
| **Weighted Average Common Shares Outstanding, Diluted** | **501** | **487** | **470** |
| **Net Earnings Per Common Share, Basic** | **$ 2.79** | **$ 1.81** | **$ 3.07** |
| **Net Earnings Per Common Share, Diluted** | **$ 2.78** | **$ 1.79** | **$ 3.06** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Net Income** | **$ 1,407** | **$ 888** | **$ 1,450** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations | | | |
| (net of taxes of $1, $0, and $10, at respective dates) | (2) | (1) | (14) |
| Net change in investments | | | |
| (net of taxes of $0, $12, and $17 at respective dates) | - | (17) | (25) |
| **Total other comprehensive income (loss)** | **(2)** | **(18)** | **(39)** |
| **Comprehensive Income** | **1,405** | **870** | **1,411** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 1,391** | **$ 856** | **$ 1,397** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, 2016 | 2015 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 177 | $ 123 |
| Restricted cash | 7 | 234 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $58 and $54 at respective dates) | 1,252 | 1,106 |
| Accrued unbilled revenue | 1,098 | 855 |
| Regulatory balancing accounts | 1,500 | 1,760 |
| Other | 801 | 286 |
| Regulatory assets | 423 | 517 |
| Inventories | | |
| Gas stored underground and fuel oil | 117 | 126 |
| Materials and supplies | 346 | 313 |
| Income taxes receivable | 160 | 155 |
| Other | 283 | 338 |
| **Total current assets** | **6,164** | **5,813** |
| **Property, Plant, and Equipment** | | |
| Electric | 52,556 | 48,532 |
| Gas | 17,853 | 16,749 |
| Construction work in progress | 2,184 | 2,059 |
| Other | 2 | 2 |
| **Total property, plant, and equipment** | **72,595** | **67,342** |
| Accumulated depreciation | (22,014) | (20,619) |
| **Net property, plant, and equipment** | **50,581** | **46,723** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,951 | 7,029 |
| Nuclear decommissioning trusts | 2,606 | 2,470 |
| Income taxes receivable | 70 | 135 |
| Other | 1,226 | 1,064 |
| **Total other noncurrent assets** | **11,853** | **10,698** |
| **TOTAL ASSETS** | **$ 68,598** | **$ 63,234** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2016** | **2015** |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 1,516 | $ 1,019 |
| Long-term debt, classified as current | 700 | 160 |
| Accounts payable | | |
| Trade creditors | 1,495 | 1,414 |
| Regulatory balancing accounts | 645 | 715 |
| Other | 433 | 398 |
| Disputed claims and customer refunds | 236 | 454 |
| Interest payable | 216 | 206 |
| Other | 2,323 | 1,997 |
| **Total current liabilities** | **7,564** | **6,363** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 16,220 | 15,925 |
| Regulatory liabilities | 6,805 | 6,321 |
| Pension and other postretirement benefits | 2,641 | 2,622 |
| Asset retirement obligations | 4,684 | 3,643 |
| Deferred income taxes | 10,213 | 9,206 |
| Other | 2,279 | 2,326 |
| **Total noncurrent liabilities** | **42,842** | **40,043** |
| **Commitments and Contingencies (Note 13)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 506,891,874 and 492,025,443 shares outstanding at respective dates | 12,198 | 11,282 |
| Reinvested earnings | 5,751 | 5,301 |
| Accumulated other comprehensive loss | (9) | (7) |
| **Total shareholders' equity** | **17,940** | **16,576** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **18,192** | **16,828** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 68,598** | **$ 63,234** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,407 | $ 888 | $ 1,450 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,755 | 2,612 | 2,433 |
| Allowance for equity funds used during construction | (112) | (107) | (100) |
| Deferred income taxes and tax credits, net | 1,030 | 693 | 690 |
| Disallowed capital expenditures | 507 | 407 | 116 |
| Other | 379 | 326 | 286 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (473) | (177) | 13 |
| Butte-related insurance receivable | (575) | - | - |
| Inventories | (24) | 37 | (22) |
| Accounts payable | 180 | (55) | (61) |
| Butte-related third-party claims | 690 | - | - |
| Income taxes receivable/payable | (5) | 43 | 376 |
| Other current assets and liabilities | 83 | (288) | 218 |
| Regulatory assets, liabilities, and balancing accounts, net | (1,214) | (244) | (1,642) |
| Other noncurrent assets and liabilities | (219) | (355) | (67) |
| **Net cash provided by operating activities** | **4,409** | **3,780** | **3,690** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,709) | (5,173) | (4,833) |
| Decrease in restricted cash | 227 | 64 | 3 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,295 | 1,268 | 1,336 |
| Purchases of nuclear decommissioning trust investments | (1,352) | (1,392) | (1,334) |
| Other | 13 | 22 | 114 |
| **Net cash used in investing activities** | **(5,526)** | **(5,211)** | **(4,714)** |
| **Cash Flows from Financing Activities** | | | |
| Borrowings (repayments) under revolving credit facilities | - | - | (260) |
| Net issuances (repayments) of commercial paper, net of discount of $6, $3, and $2 at respective dates | (9) | 683 | (583) |
| Short-term debt financing | 500 | - | 300 |
| Short-term debt matured | - | (300) | - |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $17, $27 and $17 at respective dates | 983 | 1,123 | 2,308 |
| Repayments of long-term debt | (160) | - | (889) |
| Common stock issued | 822 | 780 | 802 |
| Common stock dividends paid | (921) | (856) | (828) |
| Other | (44) | (27) | 29 |
| **Net cash provided by financing activities** | **1,171** | **1,403** | **879** |
| **Net change in cash and cash equivalents** | **54** | **(28)** | **(145)** |
| **Cash and cash equivalents at January 1** | **123** | **151** | **296** |
| **Cash and cash equivalents at December 31** | **$ 177** | **$ 123** | **$ 151** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | | | |
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | $ | (726) | $ | (684) | $ | (633) |
| Income taxes, net | | 231 | | 77 | | 501 |
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Common stock dividends declared but not yet paid | $ | 248 | $ | 224 | $ | 217 |
| Capital expenditures financed through accounts payable | | 403 | | 440 | | 339 |
| Noncash common stock issuances | | 20 | | 21 | | 21 |
| Terminated capital leases | | 18 | | - | | 71 |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Non controlling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2013** | **456,670,424** | **$ 9,550** | **$ 4,742** | **$ 50** | **$ 14,342** | **$ 252** | **$ 14,594** |
| Net income | - | - | 1,450 | - | 1,450 | - | 1,450 |
| Other comprehensive income | - | - | - | (39) | (39) | - | (39) |
| Common stock issued, net | 19,242,980 | 823 | - | - | 823 | - | 823 |
| Stock-based compensation amortization | - | 65 | - | - | 65 | - | 65 |
| Common stock dividends declared | - | - | (862) | - | (862) | - | (862) |
| Tax expense from employee stock plans | - | (17) | - | - | (17) | - | (17) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2014** | **475,913,404** | **$ 10,421** | **$ 5,316** | **$ 11** | **$ 15,748** | **$ 252** | **$ 16,000** |
| Net income | - | - | 888 | - | 888 | - | 888 |
| Other comprehensive loss | - | - | - | (18) | (18) | - | (18) |
| Common stock issued, net | 16,112,039 | 801 | - | - | 801 | - | 801 |
| Stock-based compensation amortization | - | 66 | - | - | 66 | - | 66 |
| Common stock dividends declared | - | - | (889) | - | (889) | - | (889) |
| Tax expense from employee stock plans | - | (6) | - | - | (6) | - | (6) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **492,025,443** | **$ 11,282** | **$ 5,301** | **$ (7)** | **$ 16,576** | **$ 252** | **$ 16,828** |
| Cumulative effect of change in accounting principle | - | - | 29 | - | 29 | - | 29 |
| Net income | - | - | 1,407 | - | 1,407 | - | 1,407 |
| Other comprehensive loss | - | - | - | (2) | (2) | - | (2) |
| Common stock issued, net | 14,866,431 | 842 | - | - | 842 | - | 842 |
| Stock-based compensation amortization | - | 74 | - | - | 74 | - | 74 |
| Common stock dividends declared | - | - | (972) | - | (972) | - | (972) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2016** | **506,891,874** | **$ 12,198** | **$ 5,751** | **$ (9)** | **$ 17,940** | **$ 252** | **$ 18,192** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Operating Revenues** | | | |
| Electric | $ 13,865 | $ 13,657 | $ 13,656 |
| Natural gas | 3,802 | 3,176 | 3,432 |
| **Total operating revenues** | **17,667** | **16,833** | **17,088** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,765 | 5,099 | 5,615 |
| Cost of natural gas | 615 | 663 | 954 |
| Operating and maintenance | 7,352 | 6,949 | 5,635 |
| Depreciation, amortization, and decommissioning | 2,754 | 2,611 | 2,432 |
| **Total operating expenses** | **15,486** | **15,322** | **14,636** |
| **Operating Income** | 2,181 | 1,511 | 2,452 |
| Interest income | 22 | 8 | 8 |
| Interest expense | (819) | (763) | (720) |
| Other income, net | 88 | 87 | 77 |
| **Income Before Income Taxes** | **1,472** | **843** | **1,817** |
| Income tax provision (benefit) | 70 | (19) | 384 |
| **Net Income** | **1,402** | **862** | **1,433** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 1,388** | **$ 848** | **$ 1,419** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Net Income** | **$ 1,402** | **$ 862** | **$ 1,433** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $1, $1, and $6, at respective dates) | (1) | (2) | (8) |
| **Total other comprehensive income (loss)** | **(1)** | **(2)** | **(8)** |
| **Comprehensive Income** | **$ 1,401** | **$ 860** | **$ 1,425** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2016** | **2015** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 71 | $ 59 |
| Restricted cash | 7 | 234 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $58 and $54 at respective dates) | 1,252 | 1,106 |
| Accrued unbilled revenue | 1,098 | 855 |
| Regulatory balancing accounts | 1,500 | 1,760 |
| Other | 801 | 284 |
| Regulatory assets | 423 | 517 |
| Inventories | | |
| Gas stored underground and fuel oil | 117 | 126 |
| Materials and supplies | 346 | 313 |
| Income taxes receivable | 159 | 130 |
| Other | 282 | 338 |
| **Total current assets** | **6,056** | **5,722** |
| **Property, Plant, and Equipment** | | |
| Electric | 52,556 | 48,532 |
| Gas | 17,853 | 16,749 |
| Construction work in progress | 2,184 | 2,059 |
| **Total property, plant, and equipment** | **72,593** | **67,340** |
| Accumulated depreciation | (22,012) | (20,617) |
| **Net property, plant, and equipment** | **50,581** | **46,723** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,951 | 7,029 |
| Nuclear decommissioning trusts | 2,606 | 2,470 |
| Income taxes receivable | 70 | 135 |
| Other | 1,110 | 958 |
| **Total other noncurrent assets** | **11,737** | **10,592** |
| **TOTAL ASSETS** | **$ 68,374** | **$ 63,037** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2016** | **2015** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 1,516 | $ 1,019 |
| Long-term debt, classified as current | 700 | 160 |
| Accounts payable | | |
| Trade creditors | 1,494 | 1,414 |
| Regulatory balancing accounts | 645 | 715 |
| Other | 453 | 418 |
| Disputed claims and customer refunds | 236 | 454 |
| Interest payable | 214 | 203 |
| Other | 2,072 | 1,750 |
| **Total current liabilities** | **7,330** | **6,133** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 15,872 | 15,577 |
| Regulatory liabilities | 6,805 | 6,321 |
| Pension and other postretirement benefits | 2,548 | 2,534 |
| Asset retirement obligations | 4,684 | 3,643 |
| Deferred income taxes | 10,510 | 9,487 |
| Other | 2,230 | 2,282 |
| **Total noncurrent liabilities** | **42,649** | **39,844** |
| **Commitments and Contingencies (Note 13)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 8,050 | 7,215 |
| Reinvested earnings | 8,763 | 8,262 |
| Accumulated other comprehensive income | 2 | 3 |
| **Total shareholders' equity** | **18,395** | **17,060** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 68,374** | **$ 63,037** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,402 | $ 862 | $ 1,433 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,754 | 2,611 | 2,432 |
| Allowance for equity funds used during construction | (112) | (107) | (100) |
| Deferred income taxes and tax credits, net | 1,042 | 714 | 731 |
| Disallowed capital expenditures | 507 | 407 | 116 |
| Other | 306 | 263 | 226 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (475) | (177) | 16 |
| Butte-related insurance receivable | (575) | - | - |
| Inventories | (24) | 37 | (22) |
| Accounts payable | 179 | (2) | (55) |
| Butte-related third-party claims | 690 | - | - |
| Income taxes receivable/payable | (29) | 38 | 395 |
| Other current assets and liabilities | 112 | (315) | 168 |
| Regulatory assets, liabilities, and balancing accounts, net | (1,214) | (244) | (1,642) |
| Other noncurrent assets and liabilities | (219) | (340) | (66) |
| **Net cash provided by operating activities** | **4,344** | **3,747** | **3,632** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,709) | (5,173) | (4,833) |
| Decrease in restricted cash | 227 | 64 | 3 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,295 | 1,268 | 1,336 |
| Purchases of nuclear decommissioning trust investments | (1,352) | (1,392) | (1,334) |
| Other | 13 | 22 | 29 |
| **Net cash used in investing activities** | **(5,526)** | **(5,211)** | **(4,799)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $6, $3, and $2 at respective dates | (9) | 683 | (583) |
| Short-term debt financing | 500 | - | 300 |
| Short-term debt matured | - | (300) | - |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $17, $27, and $14 at respective dates | 983 | 1,123 | 1,961 |
| Repayments of long-term debt | (160) | - | (539) |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (911) | (716) | (716) |
| Equity contribution from PG&E Corporation | 835 | 705 | 705 |
| Other | (30) | (13) | 43 |
| **Net cash provided by financing activities** | **1,194** | **1,468** | **1,157** |
| **Net change in cash and cash equivalents** | **12** | **4** | **(10)** |
| **Cash and cash equivalents at January 1** | **59** | **55** | **65** |
| **Cash and cash equivalents at December 31** | **$ 71** | **$ 59** | **$ 55** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | | | |
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | $ | (717) | $ | (675) | $ | (618) |
| Income taxes, net | | 244 | | 77 | | 500 |
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Capital expenditures financed through accounts payable | $ | 403 | $ | 440 | $ | 339 |
| Terminated capital leases | | 18 | | - | | 71 |

See accompanying Notes to the Consolidated Financial Statements.

## Pacific Gas and Electric Company
## CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
## (in millions)

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2013** | **$ 258** | **$ 1,322** | **$ 5,821** | **$ 7,427** | **$ 13** | **$ 14,841** |
| Net income | - | - | - | 1,433 | - | 1,433 |
| Other comprehensive income | - | - | - | - | (8) | (8) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (12) | - | - | (12) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2014** | **$ 258** | **$ 1,322** | **$ 6,514** | **$ 8,130** | **$ 5** | **$ 16,229** |
| Net income | - | - | - | 862 | - | 862 |
| Other comprehensive loss | - | - | - | - | (2) | (2) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (4) | - | - | (4) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **$ 258** | **$ 1,322** | **$ 7,215** | **$ 8,262** | **$ 3** | **$ 17,060** |
| Cumulative effect of change in accounting principle | - | - | - | 24 | - | 24 |
| Net income | - | - | - | 1,402 | - | 1,402 |
| Other comprehensive loss | - | - | - | - | (1) | (1) |
| Equity contribution | - | - | 835 | - | - | 835 |
| Common stock dividend | - | - | - | (911) | - | (911) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2016** | **$ 258** | **$ 1,322** | **$ 8,050** | **$ 8,763** | **$ 2** | **$ 18,395** |

See accompanying Notes to the Consolidated Financial Statements.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations and cash flows during the period in which such change occurred.

### NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### Regulation and Regulated Operations

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover "revenue requirements" that have been authorized by the CPUC or the FERC based on the Utility's cost of providing service. The Utility's ability to recover a significant portion of its authorized revenue requirements through rates is generally independent, or "decoupled," from the volume of the Utility's electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

The Utility also records a regulatory balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund. In addition, the Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. These differences have no impact on net income. (See "Revenue Recognition" below.)

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable. To the extent that portions of the Utility's operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

**Revenue Recognition**

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, revenue is recognized ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled.

**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

**Restricted Cash**

Prior to October 2016, restricted cash primarily consisted of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 below.)

**Allowance for Doubtful Accounts Receivable**

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectable customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

**Inventories**

Inventories are carried at weighted-average cost and include natural gas stored underground as well as materials and supplies. Natural gas stored underground is recorded to inventory when injected and then expensed as the gas is withdrawn for distribution to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and expensed or capitalized to plant, as appropriate, when consumed or installed.

**Emission Allowances**

The Utility purchases GHG emission allowances to satisfy its compliance obligations. Associated costs are recorded as inventory and included in current assets – other and other noncurrent assets – other on the Consolidated Balance Sheets. Costs are carried at weighted-average and are recoverable through rates.

**Property, Plant, and Equipment**

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value. Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

| (in millions, except estimated useful lives) | Estimated Useful Lives (years) | Balance at December 31, 2016 | 2015 |
|---|---|---|---|
| Electricity generating facilities [1] | 5 to 100 | $ 11,308 | $ 9,860 |
| Electricity distribution facilities | 15 to 55 | 29,836 | 28,476 |
| Electricity transmission facilities | 15 to 75 | 11,412 | 10,196 |
| Natural gas distribution facilities | 5 to 60 | 11,362 | 10,397 |
| Natural gas transmission and storage facilities | 5 to 65 | 6,491 | 6,352 |
| Construction work in progress | | 2,184 | 2,059 |
| **Total property, plant, and equipment** | | **72,593** | **67,340** |
| Accumulated depreciation | | (22,012) | (20,617) |
| **Net property, plant, and equipment** | | **$ 50,581** | **$ 46,723** |

[1] Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 13 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.73% in 2016, 3.80% in 2015, and 3.77% in 2014. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $51 million and $112 million during 2016, $48 million and $107 million during 2015, and $45 million and $100 million during 2014.

**Asset Retirement Obligations**

The following table summarizes the changes in ARO liability during 2016 and 2015, including nuclear decommissioning obligations:

| (in millions) | 2016 | 2015 |
|---|---|---|
| ARO liability at beginning of year | $ 3,643 | $ 3,575 |
| Revision in estimated cash flows | 968 | 13 |
| Accretion | 194 | 169 |
| Liabilities settled | (121) | (114) |
| **ARO liability at end of year** | **$ 4,684** | **$ 3,643** |

The Utility has not recorded a liability related to certain ARO's for assets that are expected to operate in perpetuity. As the Utility cannot estimate a settlement date or range of potential settlement dates for these assets, reasonable estimates of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities associated with substations, photovoltaic facilities, and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration or land to the conditions under certain agreements.

*Nuclear Decommissioning Obligation*

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. In March 2016, the Utility submitted its updated decommissioning cost estimate to the CPUC. As a result, the estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion. The change in total estimated cost resulted in an $818 million adjustment to the ARO. The adjustment was a result of increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 (Unit 1) and 2025 (Unit 2). The application includes a joint proposal between the Utility and certain interested parties, entered into on June 20, 2016, which resulted in a $115 million increase to the ARO recognized on the Consolidated Balance Sheets in June 2016.

The Utility adjusts its nuclear decommissioning obligation to reflect changes in the estimated costs of decommissioning its nuclear power facilities and records this as an adjustment to the ARO liability on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $3.5 billion and $2.5 billion at December 31, 2016 and 2015, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $5.1 billion and $3.5 billion at December 31, 2016 and 2015 (or $7.3 billion in future dollars), respectively. These estimates are based on the 2016 decommissioning cost studies, prepared in accordance with CPUC requirements.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. (See "Enforcement and Litigation Matters" in Note 13 below.)

**Nuclear Decommissioning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2016, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2016, it did not consolidate any of them.

**Other Accounting Policies**

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies and Commitments" in Note 13 herein.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2016 consisted of the following:

| **(in millions, net of income tax)** | **Pension Benefits** | **Other Benefits** | **Total** |
|---|---|---|---|
| Beginning balance | **$ (23)** | **$ 16** | **$ (7)** |
| **Other comprehensive income before reclassifications:** | | | |
| Unrecognized prior service cost (net of taxes of $37 and $15, respectively) | 54 | (21) | 33 |
| Unrecognized net actuarial loss (net of taxes of $45 and $15, respectively) | (64) | 21 | (43) |
| Regulatory account transfer (net of taxes of $5 and $0, respectively) | 7 | - | 7 |
| **Amounts reclassified from other comprehensive income:** | | | |
| Amortization of prior service cost (net of taxes of $3 and $6, respectively) [1] | 5 | 9 | 14 |
| Amortization of net actuarial loss (net of taxes of $10 and $2, respectively) [1] | 14 | 2 | 16 |
| Regulatory account transfer (net of taxes of $13 and $8, respectively) [1] | (18) | (11) | (29) |
| **Net current period other comprehensive loss** | **(2)** | **-** | **(2)** |
| Ending balance | **$ (25)** | **$ 16** | **$ (9)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2015 consisted of the following:

| **(in millions, net of income tax)** | **Pension Benefits** | **Other Benefits** | **Other Investments** | **Total** |
|---|---|---|---|---|
| Beginning balance | $ (21) | $ 15 | $ 17 | $ 11 |
| **Other comprehensive income before reclassifications:** | | | | |
| Unrecognized net actuarial loss (net of taxes of $51, $21, and $0, respectively) | (76) | (31) | - | (107) |
| Regulatory account transfer (net of taxes of $51, $21, and $0, respectively) | 73 | 31 | - | 104 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $7, $8, and $0, respectively) [1] | 8 | 11 | - | 19 |
| Amortization of net actuarial loss (net of taxes of $4, $1, and $0, respectively) [1] | 6 | 3 | - | 9 |
| Regulatory account transfer (net of taxes of $10, $9, and $0, respectively) [1] | (13) | (13) | - | (26) |
| Realized gain on investments (net of taxes of $0, $0, and $12, respectively) | - | - | (17) | (17) |
| **Net current period other comprehensive loss** | **(2)** | **1** | **(17)** | **(18)** |
| **Ending balance** | **$ (23)** | **$ 16** | **$ -** | **$ (7)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

## Recently Adopted Accounting Guidance

### *Share-Based Payment Accounting*

In March 2016, the FASB issued ASU No. 2016-09, *Compensation – Stock Compensation (Topic 718)*, which amends the existing guidance relating to the accounting for share-based payment awards issued to employees, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. PG&E Corporation and the Utility have adopted this standard as of the fourth quarter of 2016.

ASU 2016-09 requires recognition of excess tax benefits and deficiencies in the income statement, which resulted in the recognition of $6.3 million in income tax benefit for PG&E Corporation and the Utility for the year ended December 31, 2016. Previously, these amounts were recognized in additional paid-in capital. Previously unrecognized excess tax benefits were reclassified via a cumulative-effect adjustment. ASU 2016-09 also requires excess tax benefits and deficiencies to be prospectively excluded from assumed future proceeds in the calculation of diluted shares when calculating diluted earnings per share utilizing the treasury stock method. The effect of this change on diluted EPS is immaterial. Additionally, excess income tax benefits from stock-based compensation arrangements are now classified as cash flows from operating activities rather than as cash flows from financing activities, which resulted in an increase to cash flows from operating activities of approximately $7.2 million for the year ended December 31, 2016.

Furthermore, ASU 2016-09 requires, on a retrospective basis, that employee taxes paid for withheld shares be classified as cash flows from financing activities rather than as cash flows from operating activities. As such, the consolidated statements of cash flows for PG&E Corporation and the Utility for the prior periods presented were restated. This change resulted in an increase to cash flows from operating activities and a decrease to cash flows from financing activities of $34.6 million, $26.8 million, and $13.2 million for the years ended December 31, 2016, 2015, and 2014, respectively.

PG&E Corporation and the Utility have elected to continue to estimate forfeitures expected to occur to determine the amount of compensation cost to be recognized in each period and have not changed their policy on statutory withholding requirements and will continue to allow the employee to withhold up to the minimum statutory withholding requirements.

### *Fair Value Measurement*

In May 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*, which standardizes reporting practices related to the fair value hierarchy for all investments for which fair value is measured using net asset value per share. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this standard did not have a material impact on their Consolidated Financial Statements. All prior periods presented in these Consolidated Financial Statements reflect the retrospective adoption of this guidance. (See Notes 10 and 11 below.)

### *Accounting for Fees Paid in a Cloud Computing Arrangement*

In April 2015, the FASB issued ASU No. 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement,* which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this guidance did not have a material impact on their Consolidated Financial Statements.

### *Presentation of Debt Issuance Costs*

In April 2015, the FASB issued ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,* which amends the existing guidance relating to the presentation of debt issuance costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this guidance did not have a material impact on their Consolidated Financial Statements. PG&E Corporation and the Utility restated $105 million and $103 million, respectively, of debt issuance costs as of December 31, 2015 with no impact to net income or total shareholders' equity previously reported. All prior periods presented in these Consolidated Financial Statements reflect the retrospective adoption of this guidance.

## Accounting Standards Issued But Not Yet Adopted

### *Restricted Cash*

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows – Restricted Cash (Topic 230)*, which amends the existing guidance relating to the disclosure of restricted cash and restricted cash equivalents on the statement of cash flows. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Statements of Cash Flows.

### *Recognition of Lease Assets and Liabilities*

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which amends the existing guidance relating to the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheet, which were previously not recognized. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019 with retrospective application. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

### *Recognition and Measurement of Financial Assets and Financial Liabilities*

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*, which amends the existing guidance relating to the recognition and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

### *Revenue Recognition Standard*

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which amends existing revenue recognition guidance, effective January 1, 2018. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability across entities, industries, jurisdiction, and capital markets and to provide more useful information to users of financial statements through improved disclosure requirements. PG&E Corporation and the Utility do not plan to early adopt the standard and are currently reviewing all revenue streams and evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures. The Utility does not expect ASU 2014-09 to materially impact the timing or recognition of revenue generated through the sale and delivery of electricity and natural gas to customers. However, the Utility continues to consider the impacts of outstanding industry-related issues being addressed by the American Institute of CPAs' Revenue Recognition Working Group and the FASB's Transition Resource Group.

## NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

### Regulatory Assets

Long-term regulatory assets are comprised of the following:

| (in millions) | Balance at December 31, 2016 | Balance at December 31, 2015 | Recovery Period |
|---|---|---|---|
| Pension benefits [1] | $ 2,429 | $ 2,414 | Indefinitely (3) |
| Deferred income taxes [1] | 3,859 | 3,054 | 47 years |
| Utility retained generation [2] | 364 | 411 | 9 years |
| Environmental compliance costs [1] | 778 | 748 | 32 years |
| Price risk management [1] | 92 | 138 | 10 years |
| Unamortized loss, net of gain, on reacquired debt [1] | 76 | 94 | 26 years |
| Other | 353 | 170 | Various |
| **Total long-term regulatory assets** | **$ 7,951** | **$ 7,029** | |

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recognized in accordance with GAAP.
(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.
(3) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the Utility expects to continuously recover pension benefits.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

### Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Balance at December 31, 2016 | Balance at December 31, 2015 |
|---|---|---|
| Cost of removal obligations [1] | $ 5,060 | $ 4,605 |
| Recoveries in excess of AROs [2] | 626 | 631 |
| Public purpose programs [3] | 567 | 600 |
| Other | 552 | 485 |
| **Total long-term regulatory liabilities** | **$ 6,805** | **$ 6,321** |

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.
(2) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 10 below.)
(3) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

**Regulatory Balancing Accounts**

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets. These differences do not have an impact on net income. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

| | Receivable Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Electric distribution | $ 132 | $ 380 |
| Utility generation | 48 | 122 |
| Gas distribution and transmission | 541 | 493 |
| Energy procurement | 132 | 262 |
| Public purpose programs | 106 | 155 |
| Other | 541 | 348 |
| **Total regulatory balancing accounts receivable** | **$ 1,500** | **$ 1,760** |

| | Payable Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Gas distribution and transmission | $ 48 | $ - |
| Energy procurement | 13 | 112 |
| Public purpose programs | 264 | 244 |
| Other | 320 | 359 |
| **Total regulatory balancing accounts payable** | **$ 645** | **$ 715** |

The electric distribution and utility generation accounts track the collection of revenue requirements approved in the GRC. The gas distribution and transmission accounts track the collection of revenue requirements approved in the GRC and the GT&S rate case. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency.

**NOTE 4: DEBT**

**Long-Term Debt**

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

| (in millions) | | December 31, 2016 | December 31, 2015 |
|---|---|---|---|
| **PG&E Corporation** | | | |
| Senior notes: | | | |
| Maturity | Interest Rates | | |
| 2019 | 2.40% | $ 350 | $ 350 |
| Unamortized discount, net of premium and debt issuance | | (2) | (2) |
| **Total PG&E Corporation long-term debt** | | **348** | **348** |
| **Utility** | | | |
| Senior notes: | | | |
| Maturity | Interest Rates | | |
| 2017 | 5.625% | 700 | 700 |
| 2018 | 8.25% | 800 | 800 |
| 2020 | 3.50% | 800 | 800 |
| 2021 | 3.25% to 4.25% | 550 | 550 |
| 2022 through 2046 | 2.45% to 6.35% | 12,775 | 11,775 |
| Less: current portion | | (700) | - |
| Unamortized discount, net of premium and debt issuance | | (161) | (156) |
| **Total senior notes, net of current portion** | | **14,764** | **14,469** |
| Pollution control bonds: | | | |
| Maturity | Interest Rates | | |
| Series 2004 A-D, due 2023[1] | 4.75% | 345 | 345 |
| Series 2009 A-D, due 2026 [2] | variable rate[4] | 149 | 309 |
| Series 1996 C, E, F, 1997 B due 2026[3] | variable rate[5] | 614 | 614 |
| Less: current portion | | - | (160) |
| **Total pollution control bonds** | | **1,108** | **1,108** |
| **Total Utility long-term debt, net of current portion** | | **15,872** | **15,577** |
| **Total consolidated long-term debt, net of current portion** | | **$ 16,220** | **$ 15,925** |

(1) The Utility has obtained credit support from an insurance company for these bonds.
(2) Each series of these bonds is supported by a separate direct-pay letter of credit. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent. Series C and D pollution control bonds were redeemed on November 30, 2016.
(3) Each series of these bonds is supported by a separate letter of credit. In December 2015, the letters of credit were extended to December 1, 2020. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.
(4) At December 31, 2016, the interest rate on these bonds was 0.74%.
(5) At December 31, 2016, the interest rate on these bonds ranged from 0.72% - 0.73%.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sales agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. Except for components that may have been abandoned in place or disposed of as scrap or that are permanently non-operational, the Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

**Repayment Schedule**

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2016 are reflected in the table below:

| (in millions, except interest rates) | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest rate | - | - | 2.40% | - | - | - | 2.40% |
| Fixed rate obligations | $ - | $ - | $ 350 | $ - | $ - | $ - | **$** 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | 5.625% | 8.25% | - | 3.50% | 3.80% | 4.84% | 4.94% |
| Fixed rate obligations | $ 700 | $ 800 | $ - | $ 800 | $ 550 | $ 13,120 | **$** 15,970 |
| Variable interest rate as of December 31, 2016 | - | - | 0.74% | 0.73% | - | - | 0.73% |
| Variable rate obligations [1] | $ - | $ - | $ 149 | $ 614 | $ - | $ - | **$** 763 |
| **Total consolidated debt** | **$ 700** | **$ 800** | **$ 499** | **$ 1,414** | **$ 550** | **$ 13,120** | **$ 17,083** |

[1] The bonds due in 2026 are backed by separate letters of credit that expire June 5, 2019, or December 1, 2020.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at December 31, 2016:

| (in millions) | Termination Date | Credit Facility Limit | Letters of Credit Outstanding | Commercial Paper Outstanding | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2021 | $ 300 [1] | $ - | $ - | $ 300 |
| Utility | April 2021 | 3,000 [2] | 41 | 1,016 | 1,943 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 41** | **$ 1,016** | **$ 2,243** |

[1] Includes a $50 million lender commitment to the letter of credit sublimits and a $100 million commitment for swingline loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.
[2] Includes a $500 million lender commitment to the letter of credit sublimits and a $75 million commitment for swingline loans.

For the year ended December 31, 2016, PG&E Corporation's average outstanding commercial paper balance was $84 million and the maximum outstanding balance during the year was $176 million. For 2016, the Utility's average outstanding commercial paper balance was $837 million and the maximum outstanding balance during the year was $1.4 billion. There were no bank borrowings for PG&E Corporation or the Utility in 2016.

### *Revolving Credit Facilities*

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for one additional period.

Borrowings under each credit agreement (other than swingline loans) will bear interest based, at each borrower's election, on (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The applicable margin for LIBOR loans will range between 0.9% and 1.475% under PG&E Corporation's credit agreement and between 0.8% and 1.275% under the Utility's credit agreement. The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation's credit agreement and between 0% and 0.275% under the Utility's credit agreement. In addition, the facility fee under PG&E Corporation's and the Utility's credit agreements will range between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the respective revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

### *Commercial Paper Programs*

The borrowings from PG&E Corporation's and the Utility's commercial paper programs are used primarily to fund temporary financing needs. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation's and the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. For 2016, the average yield on outstanding PG&E Corporation and Utility commercial paper was 0.63% and 0.64%, respectively.

### *Other Short-term Borrowings*

In March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. Additionally, in December 2016, the Utility issued a $250 million unsecured senior floating rate note that matures on November 30, 2017. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

## NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 506,891,874 shares of common stock outstanding at December 31, 2016. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2016.

During 2016, PG&E Corporation sold 2.6 million shares of common stock under the February 2015 equity distribution agreement for cash proceeds of $149 million, net of commissions paid of $1.3 million. As of December 31, 2016, the remaining gross sales available under this agreement were $275 million.

In August 2016, PG&E Corporation sold 4.9 million shares of its common stock in an underwritten public offering for net cash proceeds of $309 million.

In addition, during 2016, PG&E Corporation sold 7.4 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $364 million.

**Dividends**

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. For the first quarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. In May 2016, the Board of Directors of PG&E Corporation adopted a new quarterly common stock dividend of $0.49 per share. In 2016, total dividends were $1.925 per share.

Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Additionally, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on a weighted average over five years. At December 31, 2016, the Utility had restricted net assets of $15.8 billion and was limited to $25 million of additional common stock dividends it could pay to PG&E Corporation.

**Long-Term Incentive Plan**

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 13,826,995 shares were available for future awards at December 31, 2016.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2016, 2015, and 2014:

| (in millions) | 2016 | 2015 | 2014 |
| --- | --- | --- | --- |
| Restricted stock units | $ 53 | $ 47 | $ 42 |
| Performance shares | 55 | 46 | 36 |
| Total compensation expense (pre-tax) | **$ 108** | **$ 93** | **$ 78** |
| Total compensation expense (after-tax) | **$ 64** | **$ 55** | **$ 47** |

The amount of share-based compensation costs capitalized during 2016, 2015, and 2014 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

Prior to 2014, restricted stock units generally vested over four years in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Restricted stock units granted after 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2016, 2015, and 2014 was $56.68, $53.30, and $43.76, respectively. The total fair value of restricted stock units that vested during 2016, 2015, and 2014 was $36 million, $57 million, and $34 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2016, $37 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.22 years.

The following table summarizes restricted stock unit activity for 2016:

| | Number of Restricted Stock Units | Weighted Average Grant-Date Fair Value | |
|---|---|---|---|
| Nonvested at January 1 | 1,972,899 | $ | 47.33 |
| Granted | 776,312 | $ | 56.68 |
| Vested | (770,968) | $ | 46.79 |
| Forfeited | (55,233) | $ | 49.65 |
| Nonvested at December 31 | **1,923,010** | $ | 51.26 |

***Performance Shares***

Performance shares generally will vest three years after the grant date. Upon vesting, performance shares are settled in shares of common stock based on either PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period or, for a small number of awards, an internal PG&E Corporation metric. Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled.

Compensation expense attributable to performance share is generally recognized rateably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value of PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2016, 2015, and 2014 was $53.61, $68.27, and $51.81 respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2016, $40 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.57 years.

The following table summarizes activity for performance shares in 2016:

| | Number of Performance Shares | Weighted Average Grant-Date Fair Value | |
|---|---|---|---|
| Nonvested at January 1 | 1,450,612 | $ | 59.24 |
| Granted | 1,233,884 | | 53.61 |
| Vested | (777,719) | | 51.81 |
| Forfeited [(1)] | (67,922) | | 58.20 |
| Nonvested at December 31 | **1,838,855** | $ | 58.65 |

[(1)] Includes performance shares that expired with zero value as performance targets were not met.

**NOTE 6: PREFERRED STOCK**

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. At December 31, 2016 and December 31, 2015, the Utility's preferred stock outstanding included $145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $113 million of shares with interest rates between 4.36% and 5% that are redeemable between $25.75 and $27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

At December 31, 2016, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2016, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid $14 million of dividends on preferred stock in each of 2016, 2015, and 2014.

## NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2016, 2015, and 2014.

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2016** | **2015** | **2014** |
| **Income available for common shareholders** | $ 1,393 | $ 874 | $ 1,436 |
| **Weighted average common shares outstanding, basic** | 499 | 484 | 468 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | 2 | 3 | 2 |
| **Weighted average common share outstanding, diluted** | 501 | 487 | 470 |
| **Total earnings per common share, diluted** | **$ 2.78** | **$ 1.79** | **$ 3.06** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

## NOTE 8: INCOME TAXES

PG&E Corporation and the Utility use the asset and liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance in the financial statements represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| (in millions) | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Current: | | | | | | |
| Federal | $ (105) | $ (89) | $ (84) | $ (105) | $ (88) | $ (84) |
| State | (70) | 11 | (41) | (66) | 6 | (29) |
| Deferred: | | | | | | |
| Federal | 218 | 131 | 396 | 229 | 136 | 426 |
| State | 16 | (76) | 78 | 16 | (69) | 75 |
| Tax credits | (4) | (4) | (4) | (4) | (4) | (4) |
| **Income tax provision (benefit)** | **$ 55** | **$ (27)** | **$ 345** | **$ 70** | **$ (19)** | **$ 384** |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| (in millions) | 2016 | 2015 | 2016 | 2015 |
| **Deferred income tax assets:** | | | | |
| Tax carryforwards | 1,851 | 1,703 | 1,596 | 1,462 |
| Other [(1)] | 463 | 757 | 402 | 700 |
| **Total deferred income tax assets** | **$ 2,314** | **$ 2,460** | **$ 1,998** | **$ 2,162** |
| **Deferred income tax liabilities:** | | | | |
| Property related basis differences | 10,429 | 9,656 | 10,411 | 9,638 |
| Income tax regulatory asset [(2)] | 1,572 | 1,244 | 1,572 | 1,245 |
| Other [(3)] | 526 | 766 | 525 | 766 |
| **Total deferred income tax liabilities** | **$ 12,527** | **$ 11,666** | **$ 12,508** | **$ 11,649** |
| **Total net deferred income tax liabilities** | **$ 10,213** | **$ 9,206** | **$ 10,510** | **$ 9,487** |

(1) Amounts include compensation and benefits, environmental reserve, and customer advances for construction.
(2) Represents the deferred income tax component of the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)
(3) Amounts primarily relate to regulatory balancing accounts. Greenhouse gas allowances are temporary timing differences that reverse through regulatory balancing accounts.

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) [1] | (2.5) | (4.9) | 1.4 | (2.2) | (4.8) | 1.6 |
| Effect of regulatory treatment of fixed asset differences [2] | (23.7) | (33.6) | (15.0) | (23.4) | (33.7) | (14.7) |
| Tax credits | (0.8) | (1.3) | (0.7) | (0.8) | (1.3) | (0.7) |
| Benefit of loss carryback | (1.1) | (1.5) | (0.8) | (1.1) | (1.5) | (0.8) |
| Non deductible penalties [3] | 0.8 | 4.3 | 0.3 | 0.8 | 4.3 | 0.3 |
| Other, net [4] | (3.9) | (1.1) | (0.8) | (3.5) | (0.2) | 0.4 |
| **Effective tax rate** | **3.8 %** | **(3.1) %** | **19.4 %** | **4.8 %** | **(2.2) %** | **21.1 %** |

(1) Includes the effect of state flow-through ratemaking treatment. In 2016 and 2015, amounts include an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.
(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacts only 2016. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.
(3) Primarily represents the effects of non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for the year ended December 31, 2016 and the effects of the Penalty Decision for the year ended December 31, 2015. For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.
(4) In 2016, the amount primarily represents the impact of tax audit settlements.

***Unrecognized tax benefits***

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| **(in millions)** | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| **Balance at beginning of year** | $ 468 | $ 713 | $ 666 | $ 462 | $ 707 | $ 660 |
| Additions for tax position taken during a prior year | - | 40 | 7 | - | 40 | 7 |
| Reductions for tax position taken during a prior year | (77) | (349) | (9) | (77) | (349) | (9) |
| Additions for tax position taken during the current year | 56 | 64 | 61 | 56 | 64 | 61 |
| Settlements | (59) | - | (12) | (59) | - | (12) |
| **Balance at end of year** | **$ 388** | **$ 468** | **$ 713** | **$ 382** | **$ 462** | **$ 707** |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2016 for PG&E Corporation and the Utility was $25 million.

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2016, it is reasonably possible that unrecognized tax benefits will decrease by approximately $70 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2016, 2015, and 2014, these amounts were immaterial.

***IRS settlements***

PG&E Corporation previously participated in the Compliance Assurance Process, a real-time IRS audit intended to expedite resolution of tax matters. The Compliance Assurance Process audit culminates with a letter from the IRS indicating its acceptance of the return. PG&E Corporation's participation in the Compliance Assurance Process ended effective with the submission of its 2015 tax return.

PG&E Corporation's tax returns have been accepted through 2015 except for a few matters, the most significant of which relates to deductible repair costs. In March 2016, PG&E Corporation reached an agreement with the IRS on deductible electric transmission and distribution repair costs for the 2012 tax year. The agreement provided that the methodology used in determining the deductible amount should be followed for all subsequent periods, absent any material change in facts. Deductible repair costs for other lines of business will continue to be subject to examination by the IRS for subsequent years. The IRS is expected to issue guidance in 2017 that clarifies which repair costs are deductible for the natural gas transmission and distribution businesses.

Tax years after 2008 remain subject to examination by the state of California.

***2015 Gas Transmission and Storage Rate Case***

In comments to the proposed decision in phase two of the 2015 GT&S rate case, the Utility questioned whether the methodology employed to calculate the capital disallowance portion of the San Bruno penalty might constitute a normalization violation. In recognition of this concern, the CPUC, in the final phase two decision, provided the Utility an opportunity to submit a ruling to the IRS for guidance and establish a memorandum account to track the additional revenue that would be recoverable if the method is deemed to be a normalization violation. The Utility anticipates filing the ruling request in early 2017.

As a result of the final phase two decision, PG&E Corporation and the Utility applied flow through accounting to property-related timing differences for 2016 and 2015.

***Carryforwards***

The following table describes PG&E Corporation's operating loss and tax credit carryforward balances:

| **(in millions)** | **December 31, 2016** | **Expiration Year** |
|---|---|---|
| **Federal:** | | |
| Net operating loss carryforward | $ 5,009 | 2029 - 2036 |
| Tax credit carryforward | 116 | 2029 - 2036 |
| Charitable contribution loss carryforward | 192 | 2017 - 2021 |
| | | |
| **State:** | | |
| Net operating loss carryforward | $ - | N/A |
| Tax credit carryforward | 51 | Various |
| Charitable contribution loss carryforward | 112 | 2019 - 2021 |

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating losses, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2016 for these tax attributes.

## NOTE 9: DERIVATIVES

### Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include forward contracts, swaps, futures, options, and CRRs.

Derivatives are presented in the Utility's Consolidated Balance Sheets on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

### Volume of Derivative Activity

At December 31, 2016 and 2015, respectively, the volumes of the Utility's outstanding derivatives were as follows:

| | | Contract Volume | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **2016** | **2015** |
| Natural Gas [1] (MMBtus [2]) | Forwards and Swaps | 323,301,331 | 333,091,813 |
| | Options | 96,602,785 | 111,550,004 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 3,287,397 | 3,663,512 |
| | Congestion Revenue Rights [3] | 278,143,281 | 216,383,389 |

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

### Presentation of Derivative Instruments in the Financial Statements

At December 31, 2016, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 91 | $ (10) | $ 1 | $ 82 |
| Other noncurrent assets – other | 149 | (9) | - | 140 |
| Current liabilities – other | (48) | 10 | - | (38) |
| Noncurrent liabilities – other | (101) | 9 | 3 | (89) |
| **Total commodity risk** | **$ 91** | **$ -** | **$ 4** | **$ 95** |

At December 31, 2015, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets – other | $ 97 | $ (4) | $ 25 | **$ 118** |
| Other noncurrent assets – other | 172 | (2) | - | **170** |
| Current liabilities – other | (102) | 4 | 44 | **(54)** |
| Noncurrent liabilities – other | (140) | 2 | 21 | **(117)** |
| **Total commodity risk** | **$ 27** | **$ -** | **$ 90** | **$ 117** |

Gains and losses associated with price risk management activities were recorded as follows:

| | Commodity Risk | | |
|---|---|---|---|
| | For the year ended December 31, | | |
| **(in millions)** | **2016** | **2015** | **2014** |
| Unrealized gain/(loss) - regulatory assets and liabilities (1) | $ 64 | $ (6) | $ 124 |
| Realized loss - cost of electricity (2) | (53) | (14) | (83) |
| Realized loss - cost of natural gas (2) | (18) | (10) | (8) |
| **Total commodity risk** | **$ (7)** | **$ (30)** | **$ 33** |

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2016, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (24) | $ (2) |
| Related derivatives in an asset position | 19 | - |
| Collateral posting in the normal course of business related to these derivatives | 4 | - |
| **Net position of derivative contracts/additional collateral posting requirements (1)** | **$ (1)** | **$ (2)** |

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

**NOTE 10: FAIR VALUE MEASUREMENTS**

PG&E Corporation and the Utility measure their cash equivalents, trust assets and price risk management instruments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.

- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2016 | | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Netting [(1)]** | **Total** |
| **Assets:** | | | | | |
| Short-term investments | $ 105 | $ - | $ - | $ - | **$ 105** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 9 | - | - | - | **9** |
| Global equity securities | 1,724 | - | - | - | **1,724** |
| Fixed-income securities | 665 | 527 | - | - | **1,192** |
| Assets measured at NAV | - | - | - | - | **14** |
| **Total nuclear decommissioning trusts [(2)]** | **2,398** | **527** | **-** | **-** | **2,939** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 30 | 18 | 181 | (18) | **211** |
| Gas | - | 11 | - | - | **11** |
| **Total price risk management instruments** | **30** | **29** | **181** | **(18)** | **222** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 61 | - | - | **61** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **131** | **-** | **-** | **131** |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | - | - | - | **8** |
| Assets measured at NAV | - | - | - | - | **170** |
| **Total long-term disability trust** | **8** | **-** | **-** | **-** | **178** |
| **TOTAL ASSETS** | **$ 2,541** | **$ 687** | **$ 181** | **$ (18)** | **$ 3,575** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 9 | $ 12 | $ 126 | $ (21) | **$ 126** |
| Gas | - | 2 | - | (1) | **1** |
| **TOTAL LIABILITIES** | **$ 9** | **$ 14** | **$ 126** | **$ (22)** | **$ 127** |

[(1)] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[(2)] Represents amount before deducting $333 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2015 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Short-term investments | $ 64 | $ - | $ - | $ - | **$ 64** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 36 | - | - | - | **36** |
| Global equity securities | 1,520 | - | - | - | **1,520** |
| Fixed-income securities | 694 | 521 | - | - | **1,215** |
| Assets measured at NAV | - | - | - | - | **13** |
| **Total nuclear decommissioning trusts [2]** | **2,250** | **521** | **-** | **-** | **2,784** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | - | 9 | 259 | 18 | **286** |
| Gas | - | 1 | - | 1 | **2** |
| **Total price risk management instruments** | **-** | **10** | **259** | **19** | **288** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 57 | - | - | **57** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **127** | **-** | **-** | **127** |
| Long-term disability trust | | | | | |
| Short-term investments | 7 | - | - | - | **7** |
| Assets measured at NAV | - | - | - | - | **158** |
| **Total long-term disability trust** | **7** | **-** | **-** | **-** | **165** |
| **TOTAL ASSETS** | **$ 2,321** | **$ 658** | **$ 259** | **$ 19** | **$ 3,428** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 69 | $ 1 | $ 170 | $ (70) | **$ 170** |
| Gas | - | 2 | - | (1) | **1** |
| **TOTAL LIABILITIES** | **$ 69** | **$ 3** | **$ 170** | **$ (71)** | **$ 171** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $314 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the years ended December 31, 2016 and 2015.

***Trust Assets***

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* and applied it retrospectively for the periods presented in their Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Financial Officer, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

| (in millions) | Fair Value at At December 31, 2016 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [1] |
| Congestion revenue rights | $ 181 | $ 35 | Market approach | CRR auction prices | $ (11.88) - 6.93 |
| Power purchase agreements | $ - | $ 91 | Discounted cash flow | Forward prices | $ 18.07 - 38.80 |

[1] Represents price per megawatt-hour

| (in millions) | Fair Value at At December 31, 2015 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [1] |
| Congestion revenue rights | $ 259 | $ 63 | Market approach | CRR auction prices | $ (161.36) - 8.76 |
| Power purchase agreements | $ - | $ 107 | Discounted cash flow | Forward prices | $ 15.08 - 37.27 |

[1] Represents price per megawatt-hour

**Level 3 Reconciliation**

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2016 and 2015, respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| (in millions) | 2016 | 2015 |
| Asset (liability) balance as of January 1 | **$ 89** | **$ 69** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | (34) | 20 |
| **Asset (liability) balance as of December 31** | **$ 55** | **$ 89** |

[1] The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2016 and 2015, as they are short-term in nature or have interest rates that reset daily.
- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2016 and 2015.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| (in millions) | Carrying Amount | Level 2 Fair Value | Carrying Amount | Level 2 Fair Value |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 348 | $ 352 | $ 348 | $ 354 |
| Utility | 15,813 | 17,790 | 14,818 | 16,422 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| **As of December 31, 2016** | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 9 | $ - | $ - | $ 9 |
| Global equity securities | 584 | 1,157 | (3) | 1,738 |
| Fixed-income securities | 1,156 | 48 | (12) | 1,192 |
| **Total** (1) | **$ 1,749** | **$ 1,205** | **$ (15)** | **$ 2,939** |
| **As of December 31, 2015** | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 36 | $ - | $ - | $ 36 |
| Global equity securities | 508 | 1,034 | (9) | 1,533 |
| Fixed-income securities | 1,165 | 58 | (8) | 1,215 |
| **Total** (1) | **$ 1,709** | **$ 1,092** | **$ (17)** | **$ 2,784** |

(1) Represents amounts before deducting $333 million and $314 million at December 31, 2016 and 2015, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

| (in millions) | As of December 31, 2016 |
|---|---|
| Less than 1 year | $ 13 |
| 1–5 years | 419 |
| 5–10 years | 255 |
| More than 10 years | 505 |
| **Total maturities of fixed-income securities** | **$ 1,192** |

The following table provides a summary of activity for the fixed-income and equity securities:

| (in millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning investments | $ 1,295 | $ 1,268 | $ 1,336 |
| Gross realized gains on securities held as available-for-sale | 18 | 55 | 118 |
| Gross realized losses on securities held as available-for-sale | (26) | (37) | (12) |

**NOTE 11: EMPLOYEE BENEFIT PLANS**

**Pension Plan and Postretirement Benefits Other than Pensions ("PBOP")**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans is zero.

PG&E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utility use a fiscal year-end measurement date for all plans.

**Change in Plan Assets, Benefit Obligations, and Funded Status**

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2016 and 2015:

***Pension Plan***

| **(in millions)** | **2016** | **2015** |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 13,745** | **$ 14,216** |
| Actual return on plan assets | 1,358 | (176) |
| Company contributions | 334 | 334 |
| Benefits and expenses paid | (708) | (629) |
| **Fair value of plan assets at end of year** | **$ 14,729** | **$ 13,745** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 16,299** | **$ 16,696** |
| Service cost for benefits earned | 453 | 479 |
| Interest cost | 715 | 673 |
| Actuarial (gain) loss | 637 | (922) |
| Plan amendments | (91) | 1 |
| Transitional costs | - | 1 |
| Benefits and expenses paid | (708) | (629) |
| **Benefit obligation at end of year** [(1)] | **$ 17,305** | **$ 16,299** |
| | | |
| **Funded Status:** | | |
| Current liability | $ (7) | $ (6) |
| Noncurrent liability | (2,569) | (2,547) |
| **Net liability at end of year** | **$ (2,576)** | **$ (2,553)** |

(1) PG&E Corporation's accumulated benefit obligation was $15.6 billion and $14.7 billion at December 31, 2016 and 2015, respectively.

***Postretirement Benefits Other than Pensions***

| (in millions) | 2016 | 2015 |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 2,035** | **$ 2,092** |
| Actual return on plan assets | 167 | (26) |
| Company contributions | 52 | 61 |
| Plan participant contribution | 85 | 68 |
| Benefits and expenses paid | (166) | (160) |
| **Fair value of plan assets at end of year** | **$ 2,173** | **$ 2,035** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 1,766** | **$ 1,811** |
| Service cost for benefits earned | 52 | 55 |
| Interest cost | 76 | 71 |
| Actuarial (gain) loss | 11 | (98) |
| Plan amendments | 37 | - |
| Transitional costs | - | 1 |
| Benefits and expenses paid | (153) | (146) |
| Federal subsidy on benefits paid | 3 | 4 |
| Plan participant contributions | 85 | 68 |
| **Benefit obligation at end of year** | **$ 1,877** | **$ 1,766** |
| | | |
| Funded Status: [1] | | |
| Noncurrent asset | $ 368 | $ 344 |
| Noncurrent liability | (72) | (75) |
| **Net asset at end of year** | **$ 296** | **$ 269** |

[1] At December 31, 2016 and 2015, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

***Pension Plan***

| (in millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Service cost | $ 453 | $ 479 | $ 383 |
| Interest cost | 715 | 673 | 695 |
| Expected return on plan assets | (828) | (873) | (807) |
| Amortization of prior service cost | 8 | 15 | 20 |
| Amortization of net actuarial loss | 24 | 10 | 2 |
| **Net periodic benefit cost** | **372** | **304** | **293** |
| Less: transfer to regulatory account [1] | (34) | 34 | 42 |
| **Total expense recognized** | **$ 338** | **$ 338** | **$ 335** |

[1] The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

***Postretirement Benefits Other than Pensions***

| (in millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Service cost | $ 52 | $ 55 | $ 45 |
| Interest cost | 76 | 71 | 76 |
| Expected return on plan assets | (107) | (112) | (103) |
| Amortization of prior service cost | 15 | 19 | 23 |
| Amortization of net actuarial loss | 4 | 4 | 2 |
| **Net periodic benefit cost** | **$ 40** | **$ 37** | **$ 43** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record unrecognized prior service costs and unrecognized gains and losses related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax. In addition, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension benefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts that would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2017 are as follows:

| (in millions) | Pension Plan | PBOP Plans |
|---|---|---|
| Unrecognized prior service cost | $ (7) | $ 15 |
| Unrecognized net loss | 22 | 4 |
| **Total** | **$ 15** | **$ 19** |

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

**Valuation Assumptions**

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | December 31, | | | December 31, | | |
| | 2016 | 2015 | 2014 | 2016 | 2015 | 2014 |
| **Discount rate** | 4.11 % | 4.37 % | 4.00 % | 4.05 - 4.19 % | 4.27 - 4.48 % | 3.89 - 4.09 % |
| **Rate of future compensation increases** | 4.00 % | 4.00 % | 4.00 % | - | - | - |
| **Expected return on plan assets** | 5.30 % | 6.10 % | 6.20 % | 2.80 - 6.00 % | 3.20 - 6.60 % | 3.30 - 6.70 % |

The assumed health care cost trend rate as of December 31, 2016 was 7.2%, decreasing gradually to an ultimate trend rate in 2025 and beyond of approximately 4.5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| **(in millions)** | **One-Percentage-Point Increase** | **One-Percentage-Point Decrease** |
|---|---|---|
| Effect on postretirement benefit obligation | $ 118 | $ (120) |
| Effect on service and interest cost | 9 | (10) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 5.3% compares to a ten-year actual return of 7.3%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 696 Aa-grade non-callable bonds at December 31, 2016. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

**Investment Policies and Strategies**

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs in financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts' asset allocations are meant to manage volatility, reduce costs, and diversify its holdings. Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts' fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility, PG&E Corporation's and the Utility's trusts hold significant allocations in long maturity fixed-income investments. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, global REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

In the Pension Plan, target allocations for 2017 were updated to reflect a 2% increase in global equity investments and a 2% decrease in fixed income investments. Target allocations for PBOP Plans remain unchanged. Derivative instruments such as equity index futures are used to meet target equity exposure. Derivative instruments, such as equity index futures and U.S. treasury futures, are also used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are used to hedge a portion of the non U.S. dollar exposure of global equity investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | **Pension Plan** | | | **PBOP Plans** | | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| Global equity | 27 % | 25 % | 25 % | 32 % | 32 % | 31 % |
| Absolute return | 5 % | 5 % | 5 % | 3 % | 3 % | 3 % |
| Real assets | 10 % | 10 % | 10 % | 7 % | 7 % | 8 % |
| Fixed income | 58 % | 60 % | 60 % | 58 % | 58 % | 58 % |
| **Total** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** |

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

### Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2016 and 2015.

| | **Fair Value Measurements** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **At December 31,** | | | | | | | |
| | **2016** | | | | **2015** | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Plan:** | | | | | | | | |
| Short-term investments | $ 364 | $ 369 | $ - | **$ 733** | $ 247 | $ 375 | $ - | **$ 622** |
| Global equity | 996 | - | - | **996** | 903 | - | - | **903** |
| Real assets | 610 | - | - | **610** | 581 | - | - | **581** |
| Fixed-income | 1,754 | 4,774 | 5 | **6,533** | 1,841 | 4,495 | 3 | **6,339** |
| Assets measured at NAV | - | - | - | **5,950** | - | - | - | **5,308** |
| **Total** | **$ 3,724** | **$ 5,143** | **$ 5** | **$ 14,822** | **$ 3,572** | **$ 4,870** | **$ 3** | **$ 13,753** |
| **PBOP Plans:** | | | | | | | | |
| Short-term investments | $ 33 | $ - | $ - | **$ 33** | $ 20 | $ - | $ - | **$ 20** |
| Global equity | 115 | - | - | **115** | 104 | - | - | **104** |
| Real assets | 70 | - | - | **70** | 69 | - | - | **69** |
| Fixed-income | 150 | 656 | - | **806** | 150 | 632 | - | **782** |
| Assets measured at NAV | - | - | - | **1,153** | - | - | - | **1,065** |
| **Total** | **$ 368** | **$ 656** | **$ -** | **$ 2,177** | **$ 343** | **$ 632** | **$ -** | **$ 2,040** |
| **Total plan assets at fair value** | | | | **$ 16,999** | | | | **$ 15,793** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $97 million and $13 million at December 31, 2016 and 2015, respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

## Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

### *Short-Term Investments*

Short-term investments consist primarily of commingled funds across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

### *Global Equity*

The global equity category includes investments in common stock and equity-index futures. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets.

### *Real Assets*

The real asset category includes portfolios of commodity futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets.

### *Fixed-Income*

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

### *Assets Measured at NAV*

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* and applied it retrospectively for the periods presented in their Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the pension and PBOP plans that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges, hedge funds, private real estate funds, and fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

## Transfers Between Levels

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No material transfers between levels occurred in the years ended December 31, 2016 and 2015.

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for the pension plan that have been classified as Level 3 for the years ended December 31, 2016 and 2015:

| **(in millions)**<br>**For the year ended December 31, 2016** | **Fixed-Income** |
|---|---|
| Balance at beginning of year | $ 3 |
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | 3 |
| Relating to assets sold during the period | - |
| Purchases, issuances, sales, and settlements: | |
| Purchases | - |
| Settlements | (1) |
| **Balance at end of year** | **$ 5** |

| **(in millions)**<br>**For the year ended December 31, 2015** | **Fixed-Income** |
|---|---|
| Balance at beginning of year | $ 12 |
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | (3) |
| Relating to assets sold during the period | 1 |
| Purchases, issuances, sales, and settlements: | |
| Purchases | 2 |
| Settlements | (9) |
| **Balance at end of year** | **$ 3** |

There were no material transfers out of Level 3 in 2016 and 2015.

**Cash Flow Information**

***Employer Contributions***

PG&E Corporation and the Utility contributed $334 million to the pension benefit plans and $52 million to the other benefit plans in 2016. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2016. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $61 million to the pension plan and other postretirement benefit plans, respectively, for 2017.

***Benefits Payments and Receipts***

As of December 31, 2016, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

| (in millions) | Pension Plan | PBOP Plans | Federal Subsidy |
|---|---|---|---|
| 2017 | $ 739 | $ 87 | $ (8) |
| 2018 | 781 | 93 | (9) |
| 2019 | 821 | 97 | (10) |
| 2020 | 857 | 103 | (10) |
| 2021 | 892 | 108 | (11) |
| Thereafter in the succeeding five years | 4,879 | 592 | (15) |

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

**Retirement Savings Plan**

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were $97 million, $89 million, and $80 million in 2016, 2015, and 2014, respectively.

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

## NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions) | 2016 | 2015 | 2014 |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 7 | $ 6 | $ 5 |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 74 | $ 53 | $ 54 |
| Utility employee benefit due to PG&E Corporation | 91 | 82 | 70 |

At December 31, 2016 and 2015, the Utility had receivables of $18 million and $22 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $22 million and $21 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

**NOTE 13: CONTINGENCIES AND COMMITMENTS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows may be materially affected by the outcome of the following matters.

**Enforcement and Litigation Matters**

***CPUC Matters***

*Order Instituting an Investigation into Compliance with Ex Parte Communication Rules*

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have occurred or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker or a commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices.

On October 14, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility submitted a status report to the CPUC which proposed an update to the framework for resolving the proceeding. The revised framework includes a total of 164 communications in the scope of the proceeding. Throughout 2016, the parties jointly submitted stipulations on all of the communications, and on November 30, 2016, the parties began settlement discussions. In the event a settlement cannot be reached, the parties will brief the matter based upon the identified communications and some related discovery as well as factual stipulations and agreed upon issues of policy and law for CPUC resolution. The opening briefs are due on March 24, 2017, and reply briefs are due on April 14, 2017.

The Utility expects that the other parties may argue that the number of violations exceeds the 164 communications referenced in the October 14, 2016 joint status report either because a single communication may have violated more than one rule or because they believe some of the material provided during discovery constitutes impermissible ex parte communications. The Utility expects to contest many of these assertions. If the matter does not settle, the CPUC will determine which communications included within the scope of the proceeding were in violation of its rules. The CPUC will also determine whether to impose penalties or other remedies, as a result of a potential settlement or otherwise. The CPUC can impose fines up to $50,000 for each violation, and up to $50,000 per day if the CPUC determines that the violation was continuing. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII. In light of recent CPUC decisions, such as the Penalty Decision and the decision in the 2015 GT&S rate case, the Utility expects that such penalties could include fines and future revenue requirement reductions. In accordance with accounting rules, revenue requirement reductions would be recorded in the period they are incurred and fines would be recorded when considered probable and their amount or range can be reasonably estimated. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred because it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations.

Finally, in 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations. It is uncertain whether any charges will be brought against the Utility.

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices with respect to maintaining safe operation of its natural gas distribution service and facilities. The order also required the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cited the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014.

On August 18, 2016, the CPUC approved a final decision in this investigation. The CPUC assessed a fine of $25.6 million. With the $10.85 million citation previously paid in 2015 for the City of Carmel-by-the-Sea ("Carmel") incident, the total fine imposed on the Utility was $36.5 million. The remaining $25.6 million was paid in September 2016. The decision denied the appeals previously filed by the SED and Carmel from the presiding officer's decision, and closed this proceeding but allowed the parties an opportunity to request that this proceeding be reopened if needed to ensure proper implementation of a compliance plan to be developed by the parties.

On September 26, 2016, the SED filed an application for rehearing of the CPUC's decision. Specifically, the application indicates that the CPUC erred in certain of its determinations (including those related to maximum allowable operating pressure documentation that, if adopted, could result in an additional fine of $7 million), calculations (including those related to the missing De Anza records violations) and certain other findings, and requests that the CPUC adopt its recommendations. On October 11, 2016, the Utility submitted its response to the CPUC in which it opposed the SED's application for rehearing arguing that the application failed to identify a legal error warranting rehearing by the CPUC. The Utility cannot predict when or if the CPUC will grant the rehearing or if it will adopt the SED's recommendations.

On October 24, 2016 and November 30, 2016, the Utility held meet and confer sessions with parties to develop remedial measures necessary to address the issues identified in the CPUC decision with the objective of establishing a compliance plan. On December 16, 2016, the Utility submitted its Initial Gas Distribution Records Compliance Plan that includes feasible and cost-effective measures necessary to improve natural gas distribution system record-keeping.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

*Potential Safety Citations*

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED can consider the discretionary factors discussed above (see "Order Instituting an Investigation into Compliance with Ex Parte Communication Rules" above) in determining the number of violations and whether to impose daily fines for continuing violations. There is also an administrative limit of $8 million per citation issued.

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The Utility believes it is probable that the SED will impose penalties or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations, based on the SED's investigations of incidents reported to the CPUC, or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits or investigations. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED and other CPUC staff has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

In September 2016, the Utility reported that it discovered in November 2015 that approximately 550,000 atmospheric corrosion inspections on above-ground gas distribution meters completed in 2014, which constituted 35% of such inspections in 2014, were performed by non-operator qualified personnel. The Utility did not provide timely notification of such non-compliance to the CPUC. On December 23, 2016, the SED issued the Utility a citation with a $5.45 million fine related to this self-report. The citation included a $5.05 million fine for not ensuring that contractor inspectors were operator-qualified, a $350,000 fine for not completing inspections within 39 months from the previous inspections, and a $50,000 fine for not reporting the self-identified violations within ten days of discovery. The amount of the fine is conditioned upon the Utility implementing certain remedial measures. The Utility paid the fine in January 2017.

In February 2017, the Utility reported that it discovered in April 2014 that customer service representatives who handle gas emergency calls within the Utility's call centers are not included in the drug and alcohol testing program as required by PHMSA regulations. The Utility did not provide timely notification of such non-compliance to the CPUC. The SED could impose fines on the Utility of $50,000 per violation, and also for failure to timely file a self-report in connection with the non-compliance. The SED has the authority to issue more than one citation for a series of related incidents and can impose daily fines for continuing violations, and the CPUC can issue an OII and possible additional fines even after the SED has issued a citation. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines that could be imposed with respect to this self-report, for the reasons indicated above, or to predict whether the CPUC will open a formal proceeding.

***Federal Matters***

*Federal Criminal Trial*

On June 14, 2016, a federal criminal trial against the Utility began in the United States District Court for the Northern District of California, in San Francisco, on 12 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility obstructed the NTSB investigation into the cause of the San Bruno accident. On July 26, 2016, the court granted the government's motion to dismiss one count alleging that the Utility knowingly and willfully failed to retain a strength test pressure record with respect to a distribution feeder main, thereby reducing the total number of counts from 13 to 12.

On August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act.

On January 26, 2017, the court issued a judgment of conviction sentencing the Utility to a five-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service. The Utility has decided not to appeal the convictions. The probation includes a requirement that the Utility not commit any local, state, or federal

crimes during the probation period. As part of the probation, the Utility is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017.

At December 31, 2016, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $3 million accrual in connection with this matter. On February 1, 2017, the Utility paid the $3 million fine imposed by the court. The Utility could incur material costs, not recoverable through rates, in the event of non-compliance with the terms of probation and in connection with the monitorship (including but not limited to the monitor's compensation or costs resulting from recommendations of the monitor).

*Other Federal Matters*

In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The investigation involves a removal by the Utility of a hazardous tree that contained an osprey nest and egg in Inverness, California, on March 18, 2016. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

***Other Matters***

*Butte Fire Litigation*

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2016, complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,950 individual plaintiffs representing approximately 950 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling cases. The next case management conference is scheduled for March 2, 2017.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes it was not negligent; however, there can be no assurance that a court or jury would agree with the Utility. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and other damages that the Utility could be liable for under the theories of inverse condemnation and/or negligence.

The following table presents changes in the third-party claims liability since December 31, 2015. The balance for the third-party claims liability is included in Other current liabilities in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| Loss Accrual (in millions) | | |
|---|---|---|
| Balance at December 31, 2015 | $ | - |
| Accrued losses | | 750 |
| Payments | | (60) |
| **Balance at December 31, 2016** | **$** | **690** |

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $27 million.

The Utility believes that it is reasonably possible that it will incur losses related to Butte fire claims in excess of $750 million accrued through December 31, 2016 but is currently unable to reasonably estimate the upper end of the range of losses because it is still in an early stage of the evaluation of claims, the mediation and settlement process, and discovery. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of approximately $900 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. The Utility has recorded $625 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility is pursuing coverage under the insurance policies of its two vegetation management contractors, including under policies where the Utility is listed as an additional insured. Recoveries of any amounts under these policies are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| Insurance Receivable (in millions) | | |
|---|---|---|
| Balance at December 31, 2015 | $ | - |
| Accrued insurance recoveries | | 625 |
| Reimbursements | | (50) |
| **Balance at December 31, 2016** | **$** | **575** |

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals.

*Other Contingencies*

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $45 million at December 31, 2016 and $63 million at December 31, 2015. These amounts are included in Other current liabilities in the Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowances are reflected in operating and maintenance expenses in the Consolidated Statements of Income. Disallowances as a result of the CPUC's June 23, 2016 final phase one decision and December 1, 2016 final phase two decision in the Utility's 2015 GT&S rate case, the April 9, 2015 Penalty Decision and the Utility's Pipeline Safety Enhancement Plan are discussed below.

*2015 GT&S Rate Case Disallowance of Capital Expenditures*

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The decision permanently disallowed a portion of the 2011 through 2014 capital spending in excess of the amount adopted and established various cost caps that will increase the risk of overspend over the current rate case cycle, including new one-way capital balancing accounts. As a result, in 2016, the Utility incurred charges of $219 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This included $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $85 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending.

*Penalty Decision's Disallowance of Natural Gas Capital Expenditures*

On April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "Penalty Decision"). In January 2016, the CPUC closed the investigative proceedings. The total penalty includes (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million.

On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case, which applies $689 million of the $850 million penalty to capital expenditures. The decision also approves the Utility's list of programs and projects that meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty.

For the twelve months ended December 31, 2016, the Utility recorded charges for disallowed capital spending of $283 million as a result of the Penalty Decision. The cumulative charges at December 31, 2016, and the additional future charges that will be recognized in the first quarter of 2017 are shown in the following table:

| (in millions) | Twelve Months Ended December 31, 2016 | Cumulative Charges December 31, 2016 | Future Charges and Costs | Total Amount |
|---|---|---|---|---|
| Fine paid to the state | $ - | $ 300 | $ - | $ 300 |
| Customer bill credit paid | - | 400 | - | 400 |
| Charge for disallowed capital (1) | 283 | 689 | - | 689 |
| Disallowed revenue for pipeline safety expenses (2) | 129 | 129 | 32 | 161 |
| CPUC estimated cost of other remedies (3) | - | - | - | 50 |
| **Total Penalty Decision fines and remedies** | **$ 412** | **$ 1,518** | **$ 32** | **$ 1,600** |

(1) The Penalty Decision disallows the Utility from recovering $850 million in costs associated with pipeline safety-related projects and programs. On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case which allocates $689 million of the $850 million penalty to capital expenditures.

(2) GT&S revenues have been reduced for these unrecovered expenses. The remaining charges will be recognized in the first quarter of 2017.

(3) In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision. This table does not reflect the Utility's remedy-related costs already incurred or the Utility's estimated future remedy-related costs.

*Capital Expenditures Relating to Pipeline Safety Enhancement Plan*

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of December 31, 2016, the Utility has spent $1.35 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected to exceed the authorized amount. The Utility expects the remaining PSEP work to continue beyond 2017. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

**Environmental Remediation Contingencies**

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **December 31 2016** | **December 31, 2015** |
| Topock natural gas compressor station [1] | $ 299 | $ 300 |
| Hinkley natural gas compressor station [1] | 135 | 140 |
| Former manufactured gas plant sites owned by the Utility or third parties | 285 | 271 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites | 131 | 164 |
| Fossil fuel-fired generation facilities and sites | 108 | 94 |
| **Total environmental remediation liability** | **$ 958** | **$ 969** |

[1] See "Natural Gas Compressor Station Sites" below.

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the EPA under the federal Resource Conversation and Recovery Act as well as other state hazardous waste laws. The Utility has a comprehensive program in place designed to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at December 31, 2016 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to implement final remediation plans and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

At December 31, 2016 the Utility expected to recover $671 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

***Natural Gas Compressor Station Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Needles, California and is referred to below as the "Topock site." Another station is located near Hinkley, California and is referred to below as the "Hinkley site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

*Topock Site*

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The DTSC conducted an additional environmental review of the proposed design and issued a draft environmental impact report for public comment in January 2017. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in mid-2017. After the Utility modifies its design in response to the final report, the Utility will seek approval to begin construction of the new in-situ treatment system in late 2017 or early 2018.

*Hinkley Site*

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. In November 2015, the Regional Board adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets.

***Reasonably Possible Environmental Contingencies***

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.9 billion (including amounts related to the Topock and Hinkley sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition and cash flows during the period in which they are recorded.

**Nuclear Insurance**

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

In addition to the nuclear insurance the Utility maintains through the NEIL, the Utility also is a member of the EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at Diablo Canyon.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2016, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $60 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $2 million, as of December 31, 2016.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $13.5 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $13.5 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a maximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident. In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the liability insurance.

**Resolution of Remaining Chapter 11 Disputed Claims**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. In connection with the CPUC approved settlement agreement, on April 12, 2004, the Utility deposited approximately $1.7 billion into escrow for the payment of certain disputed claims, previously collected from customers through rates. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

On October 13, 2016, the Utility received approval from the bankruptcy court to release the remaining cash held in escrow to unrestricted cash for use by the Utility. The approval resulted in a $161 million reduction to the cash in escrow within the Restricted cash balance on the Consolidated Balance Sheets.

On September 2, 2016, the Utility's settlement became effective resolving, among other matters, the Utility's claim against the CAISO for $165 million, which includes receivables and interest. Additionally, the Utility agreed to release $66 million of cash from escrow to the California Power Exchange. The settlement resulted in a $231 million reduction to the Disputed claims and customer refunds balance on the Consolidated Balance Sheets.

At December 31, 2016 and December 31, 2015, respectively, the Consolidated Balance Sheets reflected $236 million and $454 million in net claims within Disputed claims and customer refunds. The cash held in escrow within Restricted cash was zero as of December 31, 2016 and $228 million as of December 31, 2015. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

**Purchase Commitments**

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2016:

| | Power Purchase Agreements | | | | | |
|---|---|---|---|---|---|---|
| (in millions) | Renewable Energy | Conventional Energy | Other | Natural Gas | Nuclear Fuel | Total |
| 2017 | $ 2,233 | $ 815 | $ 369 | $ 536 | $ 97 | $ 4,050 |
| 2018 | 2,108 | 716 | 284 | 169 | 93 | 3,370 |
| 2019 | 2,144 | 698 | 225 | 160 | 95 | 3,322 |
| 2020 | 2,139 | 677 | 179 | 148 | 130 | 3,273 |
| 2021 | 2,117 | 585 | 147 | 93 | 49 | 2,991 |
| Thereafter | 27,685 | 1,168 | 653 | 455 | 136 | 30,097 |
| **Total purchase commitments** | **$ 38,426** | **$ 4,659** | **$ 1,857** | **$ 1,561** | **$ 600** | **$ 47,103** |

***Third-Party Power Purchase Agreements***

In the ordinary course of business, the Utility enters into various agreements, including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

*Renewable Energy Power Purchase Agreements.* In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow. As of December 31, 2016, renewable energy contracts expire at various dates between 2017 and 2043.

*Conventional Energy Power Purchase Agreements.* The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2016, these power purchase agreements expire at various dates between 2017 and 2033.

*Other Power Purchase Agreements.* The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Several of these agreements are treated as capital leases. At December 31, 2016 and 2015, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $35 million and $54 million including accumulated amortization of $148 million and $147 million, respectively. The present value of the future minimum lease payments due under these agreements included $17 million

and $19 million in Current Liabilities and $18 million and $35 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2016, QF contracts in operation expire at various dates between 2017 and 2028. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The costs incurred for all power purchases and electric capacity amounted to $3.5 billion in 2016, $3.5 billion in 2015, and $3.6 billion in 2014.

***Natural Gas Supply, Transportation, and Storage Commitments***

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2017 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $0.7 billion in 2016, $0.9 billion in 2015, and $1.4 billion in 2014.

***Nuclear Fuel Agreements***

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2017 and 2025 and are intended to ensure long-term nuclear fuel supply. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to $100 million in 2016, $128 million in 2015, and $105 million in 2014.

**Other Commitments**

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2017 and 2052. At December 31, 2016, the future minimum payments related to these commitments were as follows:

| **(in millions)** | **Operating Leases** |
|---|---|
| 2017 | $ 44 |
| 2018 | 41 |
| 2019 | 39 |
| 2020 | 39 |
| 2021 | 36 |
| Thereafter | 168 |
| **Total minimum lease payments** | **$ 367** |

Payments for other commitments related to operating leases amounted to $43 million in 2016, $41 million in 2015, and $42 million in 2014. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

## QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

| (in millions, except per share amounts) | Quarter ended December 31 | September 30 | June 30 | March 31 |
|---|---|---|---|---|
| **2016** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues [1] | $ 4,713 | $ 4,810 | $ 4,169 | $ 3,974 |
| Operating income | 1,041 | 640 | 401 | 95 |
| Income tax provision (benefit) [2] | 160 | 70 | 12 | (187) |
| Net income [3] | 696 | 391 | 210 | 110 |
| Income available for common shareholders | 692 | 388 | 206 | 107 |
| Comprehensive income | 694 | 391 | 210 | 110 |
| Net earnings per common share, basic | 1.37 | 0.77 | 0.41 | 0.22 |
| Net earnings per common share, diluted | 1.36 | 0.77 | 0.41 | 0.22 |
| Common stock price per share: | | | | |
| High | 62.12 | 65.39 | 63.92 | 59.72 |
| Low | 58.04 | 60.82 | 56.62 | 51.29 |
| **UTILITY** | | | | |
| Operating revenues [1] | $ 4,714 | $ 4,809 | $ 4,169 | $ 3,975 |
| Operating income | 1,044 | 640 | 401 | 96 |
| Income tax provision (benefit) [2] | 169 | 73 | 13 | (185) |
| Net income [3] | 696 | 389 | 209 | 108 |
| Income available for common stock | 692 | 386 | 205 | 105 |
| Comprehensive income | 694 | 389 | 210 | 108 |
| **2015** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues | $ 4,167 | $ 4,550 | $ 4,217 | $ 3,899 |
| Operating income | 205 | 545 | 687 | 71 |
| Income tax (benefit) provision [4] | (111) | 67 | 110 | (93) |
| Net income [5] | 138 | 310 | 406 | 34 |
| Income available for common shareholders | 134 | 307 | 402 | 31 |
| Comprehensive income | 137 | 310 | 406 | 17 |
| Net earnings per common share, basic | 0.27 | 0.63 | 0.84 | 0.06 |
| Net earnings per common share, diluted | 0.27 | 0.63 | 0.83 | 0.06 |
| Common stock price per share: | | | | |
| High | 54.50 | 54.41 | 54.27 | 60.15 |
| Low | 51.65 | 47.60 | 49.10 | 51.38 |
| **UTILITY** | | | | |
| Operating revenues | $ 4,167 | $ 4,550 | $ 4,216 | $ 3,900 |
| Operating income | 208 | 544 | 687 | 72 |
| Income tax (benefit) provision [4] | (114) | 72 | 115 | (92) |
| Net income [5] | 147 | 305 | 406 | 4 |
| Income available for common stock | 143 | 302 | 402 | 1 |
| Comprehensive income | 145 | 305 | 406 | 4 |

[1] In the third and fourth quarters of 2016, the Utility recorded an increase in base revenues as authorized by the CPUC in the 2015 GT&S rate case decision.
[2] In the first quarter of 2016, the Utility had an income tax benefit, primarily due to net loss before income taxes and various tax audit results.

[3] In the first, second, and third quarters of 2016, the Utility recorded charges for disallowed capital spending of $87 million, $148 million, and $51 million, respectively, as a result of the Penalty Decision. Additionally, in the second and fourth quarters of 2016, the Utility recorded charges of $190 million and $29 million for capital expenditures probable of disallowance related to the final decision in the 2015 GT&S rate case. Also, in the first quarter of 2016 the Utility recorded a $350 million charge related to Butte Fire litigation. In the second quarter of 2016, the Utility recorded $260 million for probable insurance recoveries in connection with recovery of losses related to the Butte fire. In the fourth quarter of 2016, the Utility recorded a $400 million charge related to the Butte fire litigation and an insurance receivable of $365 million for probable insurance recoveries in connection with the Butte fire. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

[4] In the first quarter of 2015, the Utility had an income tax benefit, primarily due to the impact of the Penalty Decision. (See footnote (4) below.) In the fourth quarter of 2015, the Utility had an income tax benefit, primarily due to lower income before taxes and an audit settlement received.

[5] In the first quarter of 2015, the Utility recorded total charges of $553 million related to the Penalty Decision, including $53 million in estimated capital spending that is probable of disallowance. In the second, third, and fourth quarters of 2015, the Utility recorded $75 million, $142 million, and $137 million, respectively, in estimated capital spending that is probable of disallowance. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of PG&E Corporation and the Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2016.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2016, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and the Utility and our report dated February 16, 2017 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 16, 2017

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2016 and 2015, and the Company's related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2017 expressed an unqualified opinion on the Company's and the Utility's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 16, 2017

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

## ITEM 9A. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2016, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

### Management's Annual Report on Internal Control over Financial Reporting

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this 2016 Form 10-K under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

### Registered Public Accounting Firm's Report on Internal Control over Financial Reporting

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

### Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

Not applicable.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this 2016 Form 10-K. Other information regarding directors will be included under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on the Corporate Governance section of PG&E Corporation's website (*www.pgecorp.com/aboutus/corp_gov*) and on the Utility's website (*www.pge.com/about/company,* under the Corporate Governance tab): (1) the PG&E Corporation and the Utility's code of conduct (which meets the definition of "code of ethics" of Item 406(b) of the SEC Regulation S-K) adopted by PG&E Corporation and the Utility and applicable to their directors and employees, including their respective Chief Executive Officer and Presidents, as the case may be, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's respective corporate governance guidelines, and (3) key Board committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the code of conduct adopted by PG&E Corporation and the Utility and that apply to their respective Chief Executive Officer and Presidents, as the case may be, Chief Financial Officers, or Controllers, PG&E Corporation and the Utility will post the amended code of ethics on their websites and will disclose any waivers to the code of conduct in a Current Report on Form 8-K.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

Other than as noted below, there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2016 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

On December 16, 2016, the Boards of Directors of PG&E Corporation and the Utility each amended the applicable company's respective Bylaw provisions regarding a shareholder's right to (1) notify the company of the shareholder's intent to introduce director nominees and other matters from the floor of the annual meeting of shareholders ("floor proposals") or (2) call a special meeting of shareholders at which directors could be nominated or other business could be transacted.

In relevant part, PG&E Corporation's and the Utility's amended Bylaws (1) require that any "advance notice" of floor proposals be received between 90 and 120 days prior to the anniversary of the prior year's annual meeting (previously, the deadline was 45 days prior to the mailing date of the proxy materials for the prior year's annual meeting), (2) expand the information that must be included in a shareholder's "advance notice" of a floor proposal, including requiring additional information regarding financial interests and intentions of the shareholder, as well as additional information relating to any director nominees, and (3) result in other procedural clarifications.

The amendments to PG&E Corporation's Bylaws also establish deadlines, information requirements, and other processes relating to any PG&E Corporation shareholder's request for a special meeting of the shareholders, including meetings at which director nominees will be presented for vote.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial experts" as defined by the SEC will be included under the headings "Corporate Governance – Board Committee Duties – Audit Committees" and "Corporate Governance – Committee Membership, Independence, and Qualifications" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 11. EXECUTIVE COMPENSATION

Information responding to Item 11, for each of PG&E Corporation and the Utility, will be included under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2016," "Grants of Plan-Based Awards in 2016," "Outstanding Equity Awards at Fiscal Year End - 2016," "Option Exercises and Stock Vested During 2016," "Pension Benefits – 2016," "Non-Qualified Deferred Compensation – 2016," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2016 Director Compensation" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility will be included under the headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Equity Compensation Plan Information***

The following table provides information as of December 31, 2016 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|---|---|---|---|---|
| Equity compensation plans approved by shareholders | 6,962,072 [1] | $ | 35.53 [2] | 13,826,995 [3] |
| Equity compensation plans not approved by shareholders | - | | - | - |
| Total equity compensation plans | 6,962,072 [1] | $ | 35.53 [2] | 13,826,995 [3] |

[1] Includes 21,675 phantom stock units, 2,002,357 restricted stock units and 4,933,950 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares granted in 2014, reflects the actual payout percentage of 160%. The actual number of shares issued can range from 0% to 200% of target depending on achievement of performance objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

[2] This is the weighted average exercise price for the 4,090 options outstanding as of December 31, 2016.

[3] Represents the total number of shares available for issuance under all of PG&E Corporation's equity compensation plans as of December 31, 2016. Stock-based awards granted under these plans include restricted stock units, performance shares and phantom stock units. The 2014 LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the 2014 LTIP, less approximately 2.7 million shares for awards granted under the 2006 LTIP from January 1, 2014 through May 11, 2014. In addition, if any awards outstanding under the 2006 LTIP at December 31, 2013 are cancelled, forfeited or expire without being settled in full, shares of stock allocable to the terminated portion of such awards shall again be available for issuance under the 2014 LTIP.

For more information, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

**ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE**

Information responding to Item 13, for each of PG&E Corporation and the Utility, will be included under the headings "Related Party Transactions" and "Corporate Governance – Board and Director General Independence and Qualifications" and "Corporate Governance – Committee Membership, Independence, and Qualifications" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

Information responding to Item 14, for each of PG&E Corporation and the Utility, will be included under the heading "Information Regarding the Independent Auditor for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

**(a) The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as part of this report in Item 8:

Consolidated Statements of Income for the Years Ended December 31, 2016, 2015, and 2014 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2016, 2015, and 2014 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2016 and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015, and 2014 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2016, 2015, and 2014 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2016, 2015, and 2014 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Management's Report on Internal Controls

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Report of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2016 and 2015 and for the Years Ended December 31, 2016, 2015, and 2014.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2016, 2015, and 2014.

3. Exhibits required by Item 601 of Regulation S-K

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of December 16, 2016 |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of December 16, 2016 |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture, dated as of March 13, 2007, relating to the issuance of $700,000,000 principal amount of Pacific Gas and Electric Company's 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture, dated as of December 4, 2007, relating to the issuance of $500,000,000 principal amount of Pacific Gas and Electric Company's 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture, dated as of March 3, 2008, relating to the issuance of $200,000,000 Pacific Gas and Electric Company's 5.625% Senior Notes due November 30, 2017 and $400,000,000 of its 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture, dated as of October 21, 2008, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture, dated as of November 18, 2008, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Seventh Supplemental Indenture, dated as of June 11, 2009 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 11, 2009 (File No. 1-2348), Exhibit 4.1) |

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| 4.9 | Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Ninth Supplemental Indenture, dated as of April 1, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of its Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Tenth Supplemental Indenture, dated as of September 15, 2010, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Twelfth Supplemental Indenture, dated as of November 18, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of its 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Thirteenth Supplemental Indenture, dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Fourteenth Supplemental Indenture, dated as of September 12, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Sixteenth Supplemental Indenture, dated as of December 1, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Seventeenth Supplemental Indenture, dated as of April 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Eighteenth Supplemental Indenture, dated as of August 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of its 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Nineteenth Supplemental Indenture, dated as of June 14, 2013, relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Twentieth Supplemental Indenture, dated as of November 12, 2013, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |

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| 4.20 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No.1 2348), Exhibit 4.1) |
| 4.21 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1-2348), Exhibit 4.1) |
| 4.22 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1-2348), Exhibit 4.1) |
| 4.23 | Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.24 | Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.25 | Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.26 | Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 30, 2017 and $400,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.27 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.28 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |
| 10.1 | Second Amended and Restated Credit Agreement, dated as of April 27, 2015, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank, National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1) |

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| 10.2 | | Second Amended and Restated Credit Agreement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | | Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 2, 2016 (File No. 1-2348), Exhibit 10.1) |
| 10.4 | | Settlement Agreement among the California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K dated December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.5 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.6 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.7) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.11 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.12 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.13 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.8) |

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|---|---|---|
| 10.14 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.15 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.9) |
| 10.16 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5) |
| 10.17 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.18 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2609 and File No. 1-2348), Exhibit 10.16) |
| 10.19 | * | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2609 and File No. 1-2348), Exhibit 10.17) |
| 10.20 | * | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2609 and File No. 1-2348), Exhibit 10.18) |
| 10.21 | * | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.4) |
| 10.22 | * | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.5) |
| 10.23 | * | Non-Annual Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.6) |
| 10.24 | * | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.7) |
| 10.25 | * | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.8) |
| 10.26 | * | Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.27 | * | Separation agreement between Pacific Gas and Electric Company and Greg Kiraly dated February 18, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.3) |

| | | |
|---|---|---|
| 10.28 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and David Thomason dated May 24, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.29 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and David S. Thomason dated August 8, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1) |
| 10.30 | * | Performance Share Award Agreement subject to financial goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.31 | * | Performance Share Award Agreement subject to safety and customer affordability goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.3) |
| 10.32 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Edward D. Halpin dated November 28, 2016 |
| 10.33 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |
| 10.34 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.35 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.36 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.37 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.38 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.39 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company’s Form 8-K dated February 16, 2016 (File No. 1-12609 and File No. 1-2348) |
| 10.40 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2015 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.41 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |

| | | |
|---|---|---|
| 10.42 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.43 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.44 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.45 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-12609 and File No. 1-2348), Exhibit 10.38) |
| 10.46 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 16, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.4) |
| 10.47 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6, 2015 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2014) (File No. 1-12609), Exhibit 10.37) |
| 10.48 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.49 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.50 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2016 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-12609 and File No. 1-2348), Exhibit 10.42) |
| 10.51 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.52 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.53 | * | Form of Restricted Stock Unit Agreement for 2016 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1) |
| 10.54 | * | Form of Restricted Stock Unit Agreement for 2015 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.55 | * | Form of Restricted Stock Unit Agreement for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.56 | * | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.4) |
| 10.57 | * | Form of Restricted Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.2) |

| | | |
|---|---|---|
| 10.58 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.59 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.60 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K dated January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.61 | * | Form of Performance Share Agreement subject to financial goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.62 | * | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.5) |
| 10.63 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.64 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.6) |
| 10.65 | * | Form of Performance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.66 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |
| 10.67 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.68 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.69 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.70 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.71 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.72 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.73 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.2) |
| 10.74 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |

| | | |
|---|---|---|
| 10.75 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.76 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23 | | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

**SIGNATURES**

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2016 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| PG&E CORPORATION (Registrant) | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) |
|---|---|
| ANTHONY F. EARLEY, JR. | NICKOLAS STAVROPOULOS |
| Anthony F. Earley, Jr. | Nickolas Stavropoulos |
| By: Chairman of the Board, Chief Executive Officer, and President | By: President, Gas |
| Date: February 16, 2017 | Date: February 16, 2017 |
| | GEISHA J. WILLIAMS |
| | Geisha J. Williams |
| | By: President, Electric |
| | Date: February 16, 2017 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| **A. Principal Executive Officers** | | |
| ANTHONY F. EARLEY, JR. | Chairman of the Board, Chief Executive Officer, and President | February 16, 2017 |
| Anthony F. Earley, Jr. | (PG&E Corporation) | |
| NICKOLAS STAVROPOULOS | President, Gas | February 16, 2017 |
| Nickolas Stavropoulos | (Pacific Gas and Electric Company) | |
| GEISHA J. WILLIAMS | President, Electric | February 16, 2017 |
| Geisha J. Williams | (Pacific Gas and Electric Company) | |
| **B. Principal Financial Officers** | | |
| JASON P. WELLS | Senior Vice President and Chief Financial Officer | February 16, 2017 |
| Jason P. Wells | (PG&E Corporation) | |
| DAVID S. THOMASON | Vice President, Chief Financial Officer, and Controller | February 16, 2017 |
| David S. Thomason | (Pacific Gas and Electric Company) | |

**C. Principal Accounting Officer**

| | | |
|---|---|---|
| DAVID S. THOMASON<br>David S. Thomason | Vice President and Controller (PG&E Corporation)<br>Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 16, 2017 |

**D. Directors**

| | | |
|---|---|---|
| * LEWIS CHEW<br>Lewis Chew | Director | February 16, 2017 |
| * ANTHONY F. EARLEY, JR.<br>Anthony F. Earley, Jr. | Director | February 16, 2017 |
| * FRED J. FOWLER<br>Fred J. Fowler | Director | February 16, 2017 |
| * MARYELLEN C. HERRINGER<br>Maryellen C. Herringer | Director | February 16, 2017 |
| * RICHARD C. KELLY<br>Richard C. Kelly | Director | February 16, 2017 |
| * ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 16, 2017 |
| * RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 16, 2017 |
| * FORREST E. MILLER<br>Forrest E. Miller | Director | February 16, 2017 |
| * ERIC D. MULLINS<br>Eric D. Mullins | Director | February 16, 2017 |
| * ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 16, 2017 |
| * BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 16, 2017 |
| * ANNE SHEN SMITH<br>Anne Shen Smith | Director | February 16, 2017 |
| * NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | Director (Pacific Gas and Electric Company only) | February 16, 2017 |

| | | |
|---|---|---|
| * BARRY LAWSON WILLIAMS<br>Barry Lawson Williams | Director | February 16, 2017 |
| * GEISHA J.WILLIAMS<br>Geisha J. Williams | Director (Pacific Gas and Electric Company only) | February 16, 2017 |
| *By: HYUN PARK<br>HYUN PARK, Attorney-in-Fact | | February 16, 2017 |

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2016 and 2015, and for each of the three years in the period ended December 31, 2016, and the Company's and the Utility's internal control over financial reporting as of December 31, 2016, and have issued our reports thereon dated February 16, 2017; such consolidated financial statements and reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of the Company and the Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 16, 2017

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2016** | **2015** | **2014** |
| Administrative service revenue | $ 70 | $ 51 | $ 51 |
| Operating expenses | (73) | (53) | (53) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (10) | (10) | (14) |
| Other income (expense) | 2 | 30 | (1) |
| Equity in earnings of subsidiaries | 1,388 | 852 | 1,413 |
| Income before income taxes | 1,378 | 871 | 1,397 |
| Income tax benefit | 15 | 3 | 39 |
| **Net income** | **$ 1,393** | **$ 874** | **$ 1,436** |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $1, $0, and $10, at respective dates) | $ (2) | $ (1) | $ (14) |
| Net change in investments (net of taxes of $0, $12, and $17, at respective dates) | - | (17) | (25) |
| Total other comprehensive income (loss) | (2) | (18) | (39) |
| **Comprehensive Income** | **$ 1,391** | **$ 856** | **$ 1,397** |
| **Weighted Average Common Shares Outstanding, Basic** | **499** | **484** | **468** |
| **Weighted Average Common Shares Outstanding, Diluted** | **501** | **487** | **470** |
| **Net earnings per common share, basic** | **$ 2.79** | **$ 1.81** | **$ 3.07** |
| **Net earnings per common share, diluted** | **$ 2.78** | **$ 1.79** | **$ 3.06** |

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED BALANCE SHEETS**

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 106 | $ 64 |
| Advances to affiliates | 24 | 22 |
| Income taxes receivable | 25 | 24 |
| Other | - | 1 |
| **Total current assets** | **155** | **111** |
| **Noncurrent Assets** | | |
| Equipment | 2 | 2 |
| Accumulated depreciation | (2) | (2) |
| **Net equipment** | **-** | **-** |
| Investments in subsidiaries | 18,172 | 16,837 |
| Other investments | 133 | 130 |
| Deferred income taxes | 267 | 250 |
| **Total noncurrent assets** | **18,572** | **17,217** |
| **Total Assets** | **$ 18,727** | **$ 17,328** |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Accounts payable – other | 7 | 3 |
| Other | 274 | 246 |
| **Total current liabilities** | **281** | **249** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 348 | 348 |
| Other | 158 | 155 |
| **Total noncurrent liabilities** | **506** | **503** |
| **Common Shareholders' Equity** | | |
| Common stock | 12,198 | 11,282 |
| Reinvested earnings | 5,751 | 5,301 |
| Accumulated other comprehensive income (loss) | (9) | (7) |
| **Total common shareholders' equity** | **17,940** | **16,576** |
| **Total Liabilities and Shareholders' Equity** | **$ 18,727** | **$ 17,328** |

**PG&E CORPORATION**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Cash Flows from Operating Activities:** | | | |
| Net income | $ 1,393 | $ 874 | $ 1,436 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 74 | 66 | 65 |
| Equity in earnings of subsidiaries | (1,388) | (852) | (1,413) |
| Deferred income taxes and tax credits-net | 11 | 10 | (72) |
| Noncurrent income taxes receivable/payable | - | - | 5 |
| Current income taxes receivable/payable | (1) | 5 | (16) |
| Other | (24) | (70) | 43 |
| **Net cash provided by operating activities** | **65** | **33** | **48** |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (835) | (705) | (978) |
| Dividends received from subsidiaries [1] | 911 | 716 | 716 |
| Proceeds from tax equity investments | - | - | 368 |
| **Net cash provided by (used in) investing activities** | **76** | **11** | **106** |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings (repayments) under revolving credit facilities | - | - | (260) |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $3 | - | - | 347 |
| Repayments of long-term debt | - | - | (350) |
| Common stock issued | 822 | 780 | 802 |
| Common stock dividends paid [2] | (921) | (856) | (828) |
| **Net cash provided by (used in) financing activities** | **(99)** | **(76)** | **(289)** |
| **Net change in cash and cash equivalents** | **42** | **(32)** | **(135)** |
| **Cash and cash equivalents at January 1** | **64** | **96** | **231** |
| **Cash and cash equivalents at December 31** | **$ 106** | **$ 64** | **$ 96** |
| **Supplemental disclosure of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (9) | $ (9) | $ (15) |
| Income taxes, net | (13) | - | 1 |
| **Supplemental disclosure of noncash investing and financing activities** | | | |
| Noncash common stock issuances | $ 20 | $ 21 | $ 21 |
| Common stock dividends declared but not yet paid | 248 | 224 | 217 |

[1] Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries as an investing cash flow.
[2] In January of 2016, PG&E Corporation paid a quarterly common stock dividend of $0.455 per share.
In April, July and October of 2016, respectively, PG&E Corporation paid quarterly common stock dividends of $0.49 per share.
In January, April, July, and October of 2015 and 2014, respectively, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

**PG&E Corporation**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2016, 2015, and 2014**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions [2] | Balance at End of Period |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ - | $ 46 | $ 58 |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |
| 2014: | | | | | |
| Allowance for uncollectible accounts [1] | $ 80 | $ 41 | $ - | $ 55 | $ 66 |

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**Pacific Gas and Electric Company**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2016, 2015, and 2014**

| **(in millions)** | | Additions | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions** [2] | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ - | $ 46 | $ 58 |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |
| 2014: | | | | | |
| Allowance for uncollectible accounts [1] | $ 80 | $ 41 | $ - | $ 55 | $ 66 |

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**EXHIBIT INDEX**

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of December 16, 2016 |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of December 16, 2016 |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture, dated as of March 13, 2007, relating to the issuance of $700,000,000 principal amount of Pacific Gas and Electric Company's 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Second Supplemental Indenture, dated as of December 4, 2007, relating to the issuance of $500,000,000 principal amount of Pacific Gas and Electric Company's 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Third Supplemental Indenture, dated as of March 3, 2008, relating to the issuance of $200,000,000 Pacific Gas and Electric Company's 5.625% Senior Notes due November 30, 2017 and $400,000,000 of its 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fourth Supplemental Indenture, dated as of October 21, 2008, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Fifth Supplemental Indenture, dated as of November 18, 2008, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Sixth Supplemental Indenture, dated as of March 6, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Seventh Supplemental Indenture, dated as of June 11, 2009 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 11, 2009 (File No. 1-2348), Exhibit 4.1) |

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| 4.9 | Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Ninth Supplemental Indenture, dated as of April 1, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of its Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Tenth Supplemental Indenture, dated as of September 15, 2010, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Twelfth Supplemental Indenture, dated as of November 18, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of its 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Thirteenth Supplemental Indenture, dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Fourteenth Supplemental Indenture, dated as of September 12, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Sixteenth Supplemental Indenture, dated as of December 1, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Seventeenth Supplemental Indenture, dated as of April 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Eighteenth Supplemental Indenture, dated as of August 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of its 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Nineteenth Supplemental Indenture, dated as of June 14, 2013, relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.19 | Twentieth Supplemental Indenture, dated as of November 12, 2013, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |

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| 4.20 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No.1 2348), Exhibit 4.1) |
| 4.21 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1-2348), Exhibit 4.1) |
| 4.22 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1-2348), Exhibit 4.1) |
| 4.23 | Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.24 | Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.25 | Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.26 | Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 30, 2017 and $400,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.27 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.28 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |
| 10.1 | Second Amended and Restated Credit Agreement, dated as of April 27, 2015, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank, National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1) |

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| 10.2 | | Second Amended and Restated Credit Agreement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | | Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 2, 2016 (File No. 1-2348), Exhibit 10.1) |
| 10.4 | | Settlement Agreement among the California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K dated December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.5 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.6 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |
| 10.7 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.8 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.7) |
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.11 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3) |
| 10.12 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.13 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.8) |

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| 10.14 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.15 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.9) |
| 10.16 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5) |
| 10.17 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6) |
| 10.18 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2609 and File No. 1-2348), Exhibit 10.16) |
| 10.19 | * | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2609 and File No. 1-2348), Exhibit 10.17) |
| 10.20 | * | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2609 and File No. 1-2348), Exhibit 10.18) |
| 10.21 | * | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.4) |
| 10.22 | * | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.5) |
| 10.23 | * | Non-Annual Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.6) |
| 10.24 | * | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.7) |
| 10.25 | * | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.8) |
| 10.26 | * | Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.27 | * | Separation agreement between Pacific Gas and Electric Company and Greg Kiraly dated February 18, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.3) |

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| 10.28 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and David Thomason dated May 24, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.29 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and David S. Thomason dated August 8, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1) |
| 10.30 | * | Performance Share Award Agreement subject to financial goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.31 | * | Performance Share Award Agreement subject to safety and customer affordability goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.3) |
| 10.32 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Edward D. Halpin dated November 28, 2016 |
| 10.33 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2) |
| 10.34 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21) |
| 10.35 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.36 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.37 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.38 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.39 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company’s Form 8-K dated February 16, 2016 (File No. 1-12609 and File No. 1-2348) |
| 10.40 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2015 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.41 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |

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| 10.42 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.43 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.44 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.45 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-12609 and File No. 1-2348), Exhibit 10.38) |
| 10.46 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 16, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.4) |
| 10.47 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6, 2015 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2014) (File No. 1-12609), Exhibit 10.37) |
| 10.48 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.49 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27) |
| 10.50 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2016 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-12609 and File No. 1-2348), Exhibit 10.42) |
| 10.51 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.52 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.53 | * | Form of Restricted Stock Unit Agreement for 2016 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1) |
| 10.54 | * | Form of Restricted Stock Unit Agreement for 2015 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.55 | * | Form of Restricted Stock Unit Agreement for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.56 | * | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.4) |
| 10.57 | * | Form of Restricted Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.2) |

| | | |
|---|---|---|
| 10.58 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.59 | * | Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1) |
| 10.60 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K dated January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1) |
| 10.61 | * | Form of Performance Share Agreement subject to financial goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.62 | * | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.5) |
| 10.63 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.64 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.6) |
| 10.65 | * | Form of Performance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.66 | * | Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4) |
| 10.67 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.68 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.69 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.70 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.71 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.72 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.73 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.2) |
| 10.74 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |

| | | |
|---|---|---|
| 10.75 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.76 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23 | | Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

# Exhibit 6

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-K**

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the Fiscal Year Ended December 31, 2017**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from _________ to ___________**

| Commission File Number | Exact Name of Registrant as Specified In Its Charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company®
**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each class | Name of each exchange on which registered |
|---|---|
| **PG&E Corporation:** Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company:** First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE MKT LLC |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |



Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |
| Emerging growth company ☐ | Emerging growth company ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2017, the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $33,956 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |
| **Common Stock outstanding as of February 1, 2018:** | |
| PG&E Corporation: | 514,969,045 shares |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

| | |
|---|---|
| Designated portions of the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |



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*UNITS OF MEASUREMENT*

| | | |
|---|---|---|
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |



*GLOSSARY*

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2017 Form 10-K | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2017 |
| AB | Assembly Bill |
| AFUDC | allowance for funds used during construction |
| ARO | asset retirement obligation |
| ASU | accounting standard update issued by the FASB (see below) |
| CAISO | California Independent System Operator |
| California Water Board | California State Water Resources Control Board |
| Cal Fire | California Department of Forestry and Fire Protection |
| CARB | California Air Resources Board |
| CCA | Community Choice Aggregator |
| Central Coast Board | Central Coast Regional Water Quality Control Board |
| CEC | California Energy Resources Conservation and Development Commission |
| CEMA | Catastrophic Event Memorandum Account |
| $CO_2$ | carbon dioxide |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DER | distributed energy resources |
| DIDF | Distribution Investment Deferral Framework |

| | |
|---|---|
| Diablo Canyon | Diablo Canyon nuclear power plant |
| DOE | U.S. Department of Energy |
| DOGGR | Division of Oil, Gas and Geothermal Resources |
| DOI | U.S. Department of the Interior |
| DRP | electric distribution resources plan |
| DTSC | Department of Toxic Substances Control |
| EDA | equity distribution agreement |
| EMANI | European Mutual Association for Nuclear Insurance |
| EPA | Environmental Protection Agency |
| EPS | earnings per common share |
| EV | electric vehicle |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| HSM | hazardous substance memorandum account |
| IOUs | investor-owned utility(ies) |
| IRS | Internal Revenue Service |
| LTIP | long-term incentive plan |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K |
| NAV | net asset value |
| NDCTP | Nuclear Decommissioning Cost Triennial Proceeding |
| NEIL | Nuclear Electric Insurance Limited |
| NEM | net energy metering |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| OES | State of California Office of Emergency Services |
| OII | order instituting investigation |



| | |
|---|---|
| OIR | order instituting rulemaking |
| ORA | Office of Ratepayer Advocates |
| PCIA | Power Charge Indifference Adjustment |
| PD | proposed decision |
| PFM | petition for modification |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PSEP | pipeline safety enhancement plan |
| QF | qualifying facility |
| RAMP | Risk Assessment Mitigation Phase |
| REITS | real estate investment trust |
| ROE | return on equity |
| RPS | renewable portfolio standard |
| SB | Senate Bill |
| SEC | U.S. Securities and Exchange Commission |

| | |
|---|---|
| SED | Safety and Enforcement Division of the CPUC |
| Tax Act | Tax Cuts and Jobs Act of 2017 |
| TE | transportation electrification |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |
| WEMA | Wildfire Expense Memorandum Account |
| Westinghouse | Westinghouse Electric Company, LLC |



**PART I**

**ITEM 1. BUSINESS**

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E Corporation’s and the Utility’s operating revenues, income, and total assets can be found below in Item 6. Selected Financial Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation’s telephone number is (415) 973-1000 and the Utility’s telephone number is (415) 973-7000.

At December 31, 2017, PG&E Corporation and the Utility had approximately 23,000 regular employees, approximately 20 of which were employees of PG&E Corporation. Of the Utility’s regular employees, approximately 15,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers; the Engineers and Scientists of California; and the Service Employees International Union. The collective bargaining agreements currently in effect will expire on December 31, 2019.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. PG&E Corporation’s and the Utility’s Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, *www.pgecorp.com*, and the Utility's website, *www.pge.com*, as promptly as practicable after they are filed with, or furnished to, the SEC. Additionally, PG&E Corporation and the Utility routinely provide links to the Utility’s principal regulatory proceedings before the CPUC and the FERC at *http://investor.pgecorp.com*, under the “Regulatory Filings” tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the “News & Events: Events & Presentations” tab, in order to publicly disseminate such information.

This 2017 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation’s and the Utility’s future financial condition and results of operations, see Item 1A. Risk Factors and the section entitled “Forward-Looking Statements” in Item 7. MD&A.

**Regulatory and Enforcement Environment**

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is subject to the jurisdiction of the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies, including with respect to safety, the environment, and health. This section and the “Ratemaking Mechanisms” section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility.

PG&E Corporation is a “public utility holding company” as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

*The California Public Utilities Commission*

The CPUC is a regulatory agency that regulates privately owned public utilities in California. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electric and natural gas distribution operations, electric generation, and natural gas transmission and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electric and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $50,000 per day, per violation, for violations that occurred after January 1, 2012. (The statutory maximum penalty for violations that occurred before January 1, 2012 is $20,000 per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under the current gas and electric citation programs adopted by the CPUC in September 2016, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED has the discretion to either address each violation in a distinct citation or to include multiple violations in a single citation regardless of whether the violations occurred in the same incident or are of a similar nature. Penalty payments for citations issued pursuant to the gas and electric safety citation programs are the responsibility of shareholders of an issuer and must not be recovered in rates or otherwise directly or indirectly charged to customers.

The California State Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to increasing renewable energy resources, the development and widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, the establishment of energy storage procurement targets, and the development of a state-wide electric vehicle charging infrastructure. The CPUC is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs. The CPUC also conducts audits and reviews of the Utility’s accounting, performance, and compliance with regulatory guidelines.

The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation’s Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see “Liquidity and Financial Resources” in Item 7. MD&A and Item 1A. Risk Factors.)

*The Federal Energy Regulatory Commission and the California Independent System Operator*

The FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility’s transmission systems with other electric system and generation facilities, the tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation’s electric transmission grid, including standards to protect the nation’s bulk power system against potential disruptions from cyber and physical security breaches. The FERC has authority to impose fines of up to $1 million per day for violations of certain federal statutes and regulations.

The CAISO is the FERC-approved regional transmission organization for the Utility’s service territory. The CAISO controls the operation of the electric transmission system in California and provides open access transmission service on a non-discriminatory basis. The CAISO also is responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generating capacity, and ensuring that the reliability of the transmission system is maintained.

*The Nuclear Regulatory Commission*

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electricity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. (For more information about Diablo Canyon, see "Regulatory Matters - Diablo Canyon Nuclear Power Plant" in Item 7. MD&A and Item 1A. Risk Factors below.)

*Third-party monitor*

On April 12, 2017, the Utility retained a third-party monitor at the Utility's expense as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction, which sentenced the Utility to, among other things, a five-year corporate probation period and oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years. The goal of the monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations and maintains effective ethics, compliance, and safety related incentive programs on a Utility-wide basis. (For additional information see Item 1A. Risk Factors.)

***Other Regulators***

The CEC is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans and for adopting building and appliance energy efficiency requirements.

The CARB is the state agency responsible for setting and monitoring GHG and other emission limits. The CARB is also responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California. (See "Environmental Regulation - Air Quality and Climate Change" below.)

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and highways. In exchange for the right to use public streets and highways, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. (For additional information see Item 1A. Risk Factors.)

**Ratemaking Mechanisms**

The Utility's rates for electric and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service and a return on invested capital ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administration and general expenses) and capital costs (e.g., depreciation, tax, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Item 7. MD&A), including its costs to procure electricity, natural gas and nuclear fuel, to administer public purpose and customer programs, and to decommission its nuclear facilities.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. Similarly, the authorized rate of return on all other Utility assets is set in the CPUC's cost of capital proceeding. Other than its electric transmission and certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume. Regulatory balancing accounts, or revenue adjustment mechanisms, are designed to allow the Utility to fully collect its authorized base revenue requirements. As a result, the Utility's base revenues are not impacted by fluctuations in sales resulting from rate changes or usage. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

Due to the seasonal nature of the Utility's business and rate design, customer electric bills are generally higher during summer months (May - October) because of higher demand, driven by air conditioning loads. Customer bills related to gas service generally increase during the winter months (November - March) to account for the gas peak due to heating.

During 2017, the CPUC continued to implement state law requirements to reform residential electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. (See "Regulatory Matters" in Item 7. MD&A for more information on specific CPUC proceedings.)

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn some additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs. (See "Regulatory Matters - 2015 - 2016 Energy Efficiency Incentives Awards" in Item 7. MD&A.)

***Base Revenues***

*General Rate Cases*

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs, including return on rate base, related to its electric distribution, natural gas distribution, and Utility-owned electric generation operations. The CPUC generally conducts a GRC every three or four years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). Attrition year rate adjustments are generally provided for cost increases related to increases in invested capital and inflation. Parties in the Utility's GRC include the ORA and TURN, who generally represent the overall interests of residential customers, as well as a myriad of other intervenors who represent other business, community, customer, environmental, and union interests. The Utility plans to file the 2020 GRC in the third quarter of 2018. In December 2014, the CPUC established two new procedures concerning safety-related activities, the Safety Model Assessment Proceeding and the RAMP, preceding a utility's GRC. The purpose of the Safety Model Assessment Proceeding is to undertake a comprehensive analysis of each utility's risk-based decision making approach. The RAMP submittal includes a utility's prioritization of the risks it is facing, and a prioritization of risk mitigation alternatives, as well as a risk mitigation plan. The Utility filed its first RAMP submittal with the CPUC on November 30, 2017.

(For more information about the Utility's GRC, see "Regulatory Matters −2017 General Rate Case" and "Regulatory Matters −2020 General Rate Case" in Item 7. MD&A.)

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in the GT&S rate case. The CPUC generally conducts a GT&S rate case every three or four years. Similar to the GRC, the CPUC approves the annual revenue requirements for the first year (or "test year") of the GT&S rate case period and typically determines annual increases in revenue requirements for attrition years of the GT&S rate case period. Parties in the Utility's GT&S rate case include the ORA and TURN, who generally represent the overall interests of residential customers, as well as other intervenors who represent other business, community, customer, environmental, and union interests. The Utility filed the 2019 GT&S rate case application on November 17, 2017. (For more information, see "Regulatory Matters - 2015 Gas Transmission and Storage Rate Case" and "Regulatory Matters - 2019 Gas Transmission and Storage Rate Case" in Item 7. MD&A.)

*Cost of Capital Proceedings*

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2019, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also set the authorized ROE through 2017 at 10.40% and 10.25% beginning on January 1, 2018 and reset the cost of debt to 4.89%. The CPUC adopted an adjustment mechanism to allow the Utility's capital structure and ROE to be adjusted if the utility bond index changes by certain thresholds on an annual basis.

(For more information, see "Regulatory Matters - CPUC Cost of Capital" in Item 7. MD&A.)

*Electricity Transmission Owner Rate Cases*

The FERC determines the amount of authorized revenue requirements, including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The Utility has historically filed a TO rate case every year. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and by the CAISO in its Transmission Access Charges to wholesale customers. (For more information, see "Regulatory Matters -Transmission Owner Rate Cases" in Item 7. MD&A.) The Utility also recovers a portion of its revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are charged individualized rates based on the terms of their contracts.

***Revenues to Recover Energy Procurement and Other Pass-Through Costs***

*Electricity Procurement Costs*

California investor-owned electric utilities are responsible for procuring electrical capacity required to meet bundled customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electric contracts. The utilities are responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their bundled customer procurement plans based on long-term demand forecasts. In October 2015, the CPUC approved the Utility's most recent bundled customer procurement plan. It was revised since its initial approval and will remain in effect as revised until superseded by a subsequent CPUC-approved plan.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved bundled customer procurement plans without further after-the-fact reasonableness review by the CPUC. The CPUC may disallow costs associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to follow the principles of least-cost dispatch. Additionally, the CPUC may disallow the cost of replacement power procured due to unplanned outages at Utility-owned generation facilities.

The Utility recovers its electric procurement costs annually primarily through the energy resource recovery account. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.) Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electric rates more frequently if the forecasted aggregate over-collections or under-collections in the energy resource recovery account exceed 5% of its prior year electric procurement and Utility-owned generation revenues. The CPUC performs an annual compliance review of the transactions recorded in the energy resource recovery account.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, to meet mandatory renewable energy targets, and to comply with resource adequacy requirements. (For more information, see "Electric Utility Operations - Electricity Resources" below as well as Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

*Natural Gas Procurement, Storage, and Transportation Costs*

The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electric rates.

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as "core" customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments for its core gas portfolio, through its retail gas rates, subject to limits as set forth in its core procurement incentive mechanism described below. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rate changes.

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs for its core gas portfolio. Under the core procurement incentive mechanism, the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of these savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by FERC-approved tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. The FERC approves the United States tariffs that shippers, including the Utility, pay for pipeline service, and the applicable Canadian tariffs are approved by the National Energy Board, a Canadian regulatory agency. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as a cost of electricity.

*Costs Associated with Public Purpose and Customer Programs*

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide a discount rate for low-income customers, known as California Alternate Rates for Energy ("CARE"), which is subsidized by the Utility's other customers.

*Nuclear Decommissioning Costs*

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Nuclear decommissioning costs are collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approval of the Utility's updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility's nuclear plants.

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon's two nuclear power reactor units by 2024 and 2025. (For more information, see "Regulatory Matters" in Item 7. MD&A.)

**Electric Utility Operations**

The Utility generates electricity and provides electric transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides "bundled" services (i.e., electricity, transmission and distribution services) to most customers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations.

The Utility has continued to invest in its vision for a future electric grid which will allow customers to choose new, advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. In 2017, the Utility continued to work on the foundation for its program to deploy up to 7,500 charging stations. (For more information, see "Regulatory Matters" in Item 7. MD&A.)

***Electricity Resources***

The Utility is required to maintain generating capacity adequate to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule all of the electric resources within its portfolio in the most cost-effective way**.**

The following table shows the percentage of the Utility's total deliveries of electricity to customers in 2017 represented by each major electric resource, and further discussed below.

Total 2017 Actual Electricity Generated and Procured - 61,397 GWh [1]:

| | Percent of Bundled Retail Sales | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 27.4% | |
| Large Hydroelectric | 15.1% | |
| Fossil fuel-fired | 8.7% | |
| Small Hydroelectric | 1.7% | |
| Solar | 0.5% | |
| Total | | 53.4% |
| | | |
| Qualifying Facilities | | |
| Non-Renewable | 3.9% | |
| Renewable | 1.9% | |
| Total | | 5.8% |
| Other Third-Party Purchase Agreements | | |
| Renewable | 29.0% | |
| Non-Renewable | 7.3% | |
| Large Hydroelectric | 3.3% | |
| Total | | 39.6% |
| Others, Net [2] | | 1.2% |
| **Total [3]** | | **100%** |

[1] This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
[2] Mainly comprised of net CAISO open market purchases.
[3] Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by transmission and distribution related system losses.

*Renewable Energy Resources*

California law established an RPS that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers. In October 2015, the California Governor signed SB 350, the Clean Energy and Pollution Reduction Act of 2015 into law. SB 350 became effective January 1, 2016, and increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period, and in each three-year compliance period thereafter, unless changed by legislative action. SB 350 provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable from customers as “pass-through” costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher renewable targets. Renewable generation resources, for purposes of the RPS requirements, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. During 2017, 33.1% of the Utility’s energy deliveries were from renewable energy sources, exceeding the annual RPS target of 27%. Approximately 29% of the renewable energy delivered to the Utility’s customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (1.9%), the Utility’s small hydroelectric facilities (1.7%), and the Utility’s solar facilities (0.5%).

The total 2017 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales |
|---|---|---|
| Solar | 8,294 | 13.5% |
| Wind | 5,047 | 8.2% |
| Geothermal | 2,796 | 4.6% |
| Biopower | 2,217 | 3.6% |
| RPS-Eligible Hydroelectric | 1,943 | 3.2% |
| Total | **20,297** | **33.1%** |

*Energy Storage*

As required by California law, the CPUC has opened a proceeding to establish a multi-year energy storage procurement framework, including energy storage procurement targets to be achieved by each load-serving entity under the CPUC jurisdiction, including the Utility. Under the adopted energy storage procurement framework, the Utility is required to procure 580 MW of qualifying storage capacity by 2020, with all energy storage projects required to be operational by the end of 2024.

The CPUC also adopted biennial interim storage targets for the Utility, beginning in 2014 and ending in 2020. Under the adopted framework, the Utility is required to conduct biennial competitive request for offer to help meet its interim storage targets.

The Utility's 2017 energy storage target is 120 MW, plus an additional amount to replace failed and rejected agreements for a total of approximately 160 MW. On November 30, 2016, the Utility issued its 2016 request for offer. On December 1, 2017, the Utility submitted contracts for 165 MW of energy storage projects for CPUC review. One of the projects is a 20 MW distribution deferral project that would be Utility-owned.

The Utility currently owns or operates three battery storage facilities, each less than 10 MW.

*Owned Generation Facilities*

At December 31, 2017, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| **Generation Type** | **County Location** | **Number of Units** | **Net Operating Capacity (MW)** |
|---|---|---|---|
| Nuclear [(1)]: | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric [(2)]: | | | |
| Conventional | 16 counties in northern and central California | 103 | 2,680 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| Fuel Cell: | | | |
| CSU East Bay Fuel Cell | Alameda | 1 | 1 |
| SF State Fuel Cell | San Francisco | 2 | 2 |
| Photovoltaic [(3)]: | Various | 13 | 152 |
| **Total** | | **136** | **7,687** |

[(1)] The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses expire in 2024 and 2025, respectively. On January 11, 2018, the CPUC approved the Utility's application to retire Unit 1 by 2024 and Unit 2 by 2025. (See "Diablo Canyon Nuclear Power Plant" in. Item 7. MD&A and Item 1A. Risk Factors.)

[(2)] The Utility's hydroelectric system consists of 106 generating units at 66 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years.

[(3)] The Utility's large photovoltaic facilities are Cantua solar station (20 MW), Five Points solar station (15 MW), Gates solar station (20 MW), Giffen solar station (10 MW), Guernsey solar station (20 MW), Huron solar station (20 MW ), Stroud solar station (20 MW), West Gates solar station (10 MW), and Westside solar station (15 MW). All of these facilities are located in Fresno County, except for Guernsey solar station, which is located in Kings County.

*Generation Resources from Third Parties.*

The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. (See "Ratemaking Mechanisms" above.) For more information regarding the Utility's power purchase agreements, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

***Electricity Transmission***

At December 31, 2017, the Utility owned approximately 19,200 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 92 electric transmission substations with a capacity of approximately 64,700 MVA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes many western states, Alberta and British Columbia, and parts of Mexico.

Decisions about expansions and maintenance of the transmission system can be influenced by decisions of our regulators. For example, in 2013, the Utility, MidAmerican Transmission, LLC, and Citizens Energy Corporation were selected by the CAISO to jointly develop a new 230-kV transmission line to address the growing power demand in the Fresno, Madera and Kings counties area. However, the 2022 in-service date for the 70-mile line was subsequently postponed by the CAISO, and the CAISO has placed the project on hold. The Utility has stopped all work on the project pending a decision from the CAISO that could defer or cancel the project. A decision by the CAISO is expected by March 2018. In addition, as a part of the CAISO's 2016-2017 planning efforts, the CAISO found that a number of lower-voltage transmission projects were no longer required and recommended cancelling or requiring further review in the 2017-2018 planning cycle.

Throughout 2017, the Utility upgraded several substations and re-conductored a number of transmission lines to improve maintenance and system flexibility, reliability and safety. The Utility expects to undertake various additional transmission projects over the next several years to upgrade and expand the capacity of its transmission system to secure access to renewable generation resources and replace aging or obsolete equipment and improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment.

***Electricity Distribution***

The Utility's electric distribution network consists of approximately 107,200 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 59 transmission switching substations, and 605 distribution substations, with a capacity of approximately 31,800 MVA. The Utility’s distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility’s customers.

These distribution substations serve as the central hubs for the Utility’s electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. The Utility operates electric distribution control center facilities in Concord, Rocklin, and Fresno, California; these control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2017, the Utility continued to deploy its fault location, isolation, and service restoration circuit technology that involves the rapid operation of smart switches to reduce the duration of customer outages. Another 92 circuits were outfitted with this equipment, bringing the total deployment to 882 of the Utility’s 3,200 distribution circuits. The Utility plans to continue performing work to improve the reliability and safety of its electric distribution operations in 2018.

***Electricity Operating Statistics***

The following table shows certain of the Utility's operating statistics from 2015 to 2017 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 2017, 2016 and 2015.

| | **2017** | **2016** | **2015** |
|---|---|---|---|
| Customers (average for the year) | 5,384,525 | 5,349,691 | 5,311,178 |
| Deliveries (in GWh) [(1)] | 82,226 | 83,017 | 85,860 |
| Revenues (in millions): | | | |
| Residential | $ 5,693 | $ 5,409 | $ 5,032 |
| Commercial | 5,431 | 5,396 | 5,278 |
| Industrial | 1,603 | 1,525 | 1,555 |
| Agricultural | 1,069 | 1,226 | 1,233 |
| Public street and highway lighting | 79 | 80 | 83 |
| Other [(2)] | (294) | (68) | (84) |
| Subtotal | 13,581 | 13,568 | 13,097 |
| Regulatory balancing accounts [(3)] | (344) | 297 | 560 |
| **Total operating revenues** | **$ 13,237** | **$ 13,865** | **$ 13,657** |
| Selected Statistics: | | | |
| Average annual residential usage (kWh) | 6,231 | 6,115 | 6,294 |
| Average billed revenues per kWh: | | | |
| Residential | $ 0.1936 | $ 0.1887 | $ 0.1719 |
| Commercial | 0.1716 | 0.1716 | 0.1640 |
| Industrial | 0.1055 | 0.0990 | 0.0973 |
| Agricultural | 0.2041 | 0.1814 | 0.1610 |
| Net plant investment per customer | $ 7,486 | $ 7,195 | $ 6,660 |

[(1)] These amounts include electricity provided to direct access customers and CCAs who procure their own supplies of electricity.

[(2)] This activity is primarily related to provisions for rate refunds and unbilled electric revenue, partially offset by other miscellaneous revenue items.

[(3)] These amounts represent revenues authorized to be billed.

**Natural Gas Utility Operations**

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e., natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as core transport agents). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more than 95% of core customers, representing approximately 80% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility generally does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers, unless the customer is a natural gas-fired generation facility that the Utility has a power purchase agreement with that includes its generation fuel expense. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers (i.e., outside of the Utility's service territory) and to third-party natural gas storage customers.

*Natural Gas Supplies*

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility can also receive natural gas from fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have varied generally based on market conditions. During 2017, the Utility purchased approximately 291,100 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all of this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 14% of the total natural gas volume the Utility purchased during 2017.

*Natural Gas System Assets*

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 2017, the Utility's natural gas system consisted of approximately 42,800 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. interconnecting downstream with TransCanada Foothills Pipe Lines Ltd., B.C. System. The Foothills system interconnects at the border to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport natural gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border. Similarly, the Utility has firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport natural gas from supply points in the Southwestern United States to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas system in the area of Daggett, California. (For more information regarding the Utility's natural gas transportation agreements, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's transmission system. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later withdrawal. In addition, four independent storage operators are interconnected to the Utility's northern California transmission system. Changes to gas storage safety requirements by DOGGR have led the Utility to develop and propose in its 2019 GT&S rate case application a natural gas storage strategy which includes the discontinuation (through closure or sale) of operations at two gas storage fields. (For more information, see "Regulatory Matters" in Item 7. MD&A.)
In 2017, the Utility continued upgrading transmission pipeline to allow for the use of in-line inspection tools and continued its work on the final NTSB recommendation from its San Bruno investigation to hydrostatically test all high consequence pipeline mileage. The Utility currently plans to complete this NTSB recommendation by 2022 for remaining short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines.

***Natural Gas Operating Statistics***

The following table shows the Utility's operating statistics from 2015 through 2017 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 2017, 2016 and 2015.

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Customers (average for the year) | 4,467,657 | 4,442,379 | 4,415,332 |
| Gas purchased (MMcf) | 234,181 | 208,260 | 209,194 |
| Average price of natural gas purchased | $ 2.30 | $ 1.83 | $ 2.11 |
| Bundled gas sales (MMcf): | | | |
| Residential | 160,969 | 149,483 | 144,885 |
| Commercial | 50,329 | 46,507 | 43,888 |
| **Total Bundled Gas Sales** | **211,298** | **195,990** | **188,773** |
| Revenues (in millions): | | | |
| Bundled gas sales: | | | |
| Residential | $ 2,298 | $ 1,968 | $ 1,816 |
| Commercial | 541 | 439 | 403 |
| Other | (25) | 149 | 125 |
| Bundled gas revenues | 2,814 | 2,556 | 2,344 |
| Transportation service only revenue | 976 | 800 | 649 |
| Subtotal | 3,790 | 3,356 | 2,993 |
| Regulatory balancing accounts | 221 | 446 | 183 |
| **Total operating revenues** | **$ 4,011** | **$ 3,802** | **$ 3,176** |
| Selected Statistics: | | | |
| Average annual residential usage (Mcf) | 38 | 36 | 35 |
| Average billed bundled gas sales revenues per Mcf: | | | |
| Residential | $ 14.27 | $ 13.10 | $ 12.53 |
| Commercial | 11.36 | 9.45 | 9.18 |
| Net plant investment per customer | $ 3,093 | $ 2,808 | $ 2,573 |

**Competition**

***Competition in the Electricity Industry***

California law allows qualifying non-residential electric customers of investor-owned electric utilities to purchase electricity from energy service providers rather than from the utilities up to certain annual and overall GWh limits that have been specified for each utility. This arrangement is known as "direct access." In addition, California law permits cities, counties, and certain other public agencies that have qualified to become a CCA to generate and/or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents and businesses that do not affirmatively elect to continue to receive electricity generated or procured by a utility.

The Utility continues to provide transmission, distribution, metering, and billing services to direct access customers, although these customers can choose to obtain metering and billing services from their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Utility is able to collect charges intended to recover the generation-related costs that the Utility incurred on behalf of direct access and CCA customers while they were the Utility's customers. The Utility remains the electricity provider of last resort for these customers.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering ("NEM"), which allows self-generating customers to receive bill credits at the full retail rate, are increasing. These factors result in a shift of cost responsibility for grid and related services to other customers of the Utility. For example, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer NEM, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pressure on remaining customers. New rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers are required to pay an interconnection fee, comply with time of use rates, and are required to pay certain non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. Significantly higher bills for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers. The CPUC has indicated that it intends to revisit these rules in 2019.

Further, in some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, may seek to acquire the Utility's distribution facilities, generally through eminent domain. These same entities may, and sometimes do, construct duplicate distribution facilities to serve existing or new Utility customers.

The effect of such types of retail competition generally is to reduce the amount of electricity purchased by customers from the Utility.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission facilities within, or interconnected to, its service territory through a competitive bidding process managed by the CAISO. The FERC's transmission planning requirements rules, effective in 2011, removed the incumbent public utility transmission owners' federally-based right of first refusal to construct certain new transmission facilities and mandated regional and interregional transmission planning. In 2014, the FERC approved the CAISO's process for regional planning and competitive solicitations and the CAISO's interregional planning process.

(For risks in connection with increasing competition, see Item 1A. Risk Factors.)

***Competition in the Natural Gas Industry***

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

**Environmental Regulation**

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of $CO_2$ and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. (See Item 1A. Risk Factors.) Generally, the Utility recovers most of the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a ratemaking mechanism described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

***Hazardous Waste Compliance and Remediation***

The Utility's facilities are subject to various regulations adopted by the U.S. Environmental Protection Agency, including the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended. The Utility is also subject to the regulations adopted by other federal agencies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act, these persons (known as "potentially responsible parties") may be jointly and severally liable for the costs of cleaning up the hazardous substances, monitoring and paying for the harm caused to natural resources, and paying for the costs of health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the California DTSC, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

***Air Quality and Climate Change***

The Utility's electric generation plants, natural gas pipeline operations, vehicle fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, $CO_2$, sulfur dioxide ($SO_2$), mono-nitrogen oxide ($NO_x$), particulate matter, and other GHG emissions.

*Federal Regulation*

At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

The federal administration of President Donald Trump has led to significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. Upon taking office, President Trump issued an executive order to freeze all regulations issued in the 60 days preceding his inauguration and directed the EPA and the White House to remove climate change-related materials and web pages. In October 2017, the EPA issued a notice of proposed rulemaking to formally repeal the Clean Power Plan regulations. The Trump administration is expected to take further action to substantially limit climate related regulatory and funding activities. In light of the policy reversal at the federal level, the State of California has indicated that it intends to continue and enhance its leadership on climate change nationally and globally.

*State Regulation*

California's AB 32, the Global Warming Solutions Act of 2006, provides for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target, including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy. The cap-and-trade program's first compliance period, which began on January 1, 2013, applied to the electric generation and large industrial sectors. The next compliance period, which began on January 1, 2015, expanded to include the natural gas and transportation sectors, effectively covering all the economy's major sectors until 2020. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Emitters may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owners, and farmers) that occur outside of the emitters' facilities through CARB-qualified offset projects such as reforestation or biomass projects. SB 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. In 2017, AB 398 extended the cap-and-trade program to 2030. The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers. The California RPS program that requires the utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California.

*Climate Change Resilience Strategies*

During 2017, the Utility continued its programs to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to plan for the actions that it will need to take to increase its resilience in light of the likely impacts of climate change on the Utility's operations. The Utility regularly reviews the most relevant scientific literature on climate change such as rising sea levels, major storm events, increasing temperatures and heatwaves, wildfires, drought and land subsidence, to help the Utility identify and evaluate climate change-related risks and develop the necessary resilience strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including wildfires, extreme storms, and heat waves and uses its risk-assessment process to prioritize infrastructure investments for longer-term risks associated with climate change. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

The Utility is working to better understand the current and future impacts of climate change. In 2017, the Utility filed its first RAMP submittal with the CPUC, which examined Utility safety risks. The Climate Resilience RAMP model indicated potential additional Utility safety consequences due to climate change, including in the near term. The Utility is conducting foundational work to help anticipate and plan for evolving conditions in terms of weather and climate-change related events. This work will guide efforts to design a Utility-wide climate change risk integration strategy. This strategy will inform resource planning and investment, operational decisions, and potential additional programs to identify and pursue mitigations that will incorporate the resilience and safety of the Utility's assets, infrastructure, operations, employees, and customers.

With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme, persistent, and frequent hot weather. The Utility believes its strategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage are effective strategies for adapting to the expected changes in demand for electricity. The Utility is making substantial investments to build a more modern and resilient system that can better withstand extreme weather and related emergencies. Over the long-term, the Utility also faces the risk of higher flooding and inundation potential at coastal and low elevation facilities due to sea level rise combined with high tides, storm runoff and storm surges. As the state continues to face increased risk of wildfire, the Utility's vegetation management activities will continue to play an important role to help reduce the risk of wildfire and its impact on electric and gas facilities.

Climate scientists predict that climate change will result in varying temperatures and levels of precipitation in the Utility's service territory. This could, in turn, affect the Utility's hydroelectric generation. To plan for this potential change, the Utility is engaging with state and local stakeholders and is also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and collaborating on research and new modeling tools.

With respect to natural gas operations, both safety-related pipeline strength testing and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and volume of natural gas within pipelines prior to venting. In addition, the Utility continues to achieve reductions in methane emissions by implementing improvements in leak detection and repair, upgrades at metering and regulating stations, and maintenance and replacement of other pipeline materials.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2016, the most recent data available, totaled more than 50 million metric tonnes of $CO_2$ equivalent, three-quarters of which came from customer natural gas use. The following table shows the 2016 GHG emissions data the Utility reported to the CARB under AB 32. PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| Source | Amount (metric tonnes $CO_2$) |
|---|---|
| Fossil Fuel-Fired Plants [(1)] | 2,261,032 |
| Natural Gas Compressor Stations and Storage Facilities [(2)] | 295,851 |
| Distribution Fugitive Natural Gas Emissions | 605,690 |
| Customer Natural Gas Use [(3)] | 38,697,656 |

[(1)] Includes nitrous oxide and methane emissions from the Utility's generating stations.
[(2)] Includes emissions from compressor stations and storage facilities that are reportable to CARB.
[(3)] Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural gas local distribution companies.

The following table shows the Utility's third-party-verified $CO_2$ emissions rate associated with the electricity delivered to customers in 2016 as compared to the national average for electric utilities:

| | Amount (pounds of $CO_2$ per MWh) |
|---|---|
| U.S. Average [(1)] | 1,123 |
| Pacific Gas and Electric Company [(2)] | 294 |

[(1)] Source: EPA eGRID.
[(2)] Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's emissions rate.

***Air Emissions Data for Utility-Owned Generation***

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised approximately one-half of the Utility's delivered electricity in 2016. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | 2016 | 2015 |
|---|---|---|
| Total NOx Emissions (tons) | 141 | 160 |
| NOx Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total $SO_2$ | 13 | 17 |
| $SO_2$ | 0.001 | 0.001 |

***Water Quality***

In 2014, the EPA issued final regulations to implement the requirements of the federal Clean Water Act that require cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. Various industry and environmental groups have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Second Circuit. California's once-through cooling policy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, in 2010, the California Water Board adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The policy also provided for an alternative compliance approach for nuclear plants if certain criteria were met. As required by the policy, the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014. The report addressed feasibility, costs and timeframes to install alternative technologies at Diablo Canyon, such as cooling towers.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon's two nuclear power reactor units at the expiration of their current operating licenses in 2024 and 2025. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. As required under the policy, the Utility paid an annual interim mitigation fee beginning in 2017, which it will continue to pay until operations cease in 2025.

Additionally, the Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Board and the California Attorney General's Office regarding the thermal component of the plant's once-through cooling discharge. (For more information, see "Diablo Canyon Nuclear Power Plant" in Item 3. Legal Proceedings below.)

***Nuclear Fuel Disposal***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice ("DOJ") and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. The settlement agreement also provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. Through 2017, the Utility has been awarded an additional $114 million through these annual submissions, including $15 million for costs incurred between June 1, 2015 and May 31, 2016. The claim for the period June 1, 2016 through May 31, 2017, totaled approximately $29 million and is currently under review by the DOE. These proceeds are being refunded to customers through rates. A new settlement agreement, for costs through 2019 was executed in March 2017. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.



**ITEM 1A. RISK FACTORS**

PG&E Corporation's and the Utility's financial results can be affected by many factors, including estimates and assumptions used in the critical accounting policies described in MD&A, that can cause their actual financial results to differ materially from historical results or from anticipated future financial results. The following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with MD&A and the Consolidated Financial Statements and related Notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this Form 10-K. Any of these factors, in whole or in part, could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, cash flows, and stock price.

**Risks Related to Wildfires**

***PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions.***

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the multiple wildfires that spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City, beginning on October 8, 2017 (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The Utility incurred $219 million in costs for service restoration and repair to the Utility's facilities (including $97 million in capital expenditures) through December 31, 2017 in connection with these fires. While the Utility believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs.

The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. The CPUC's SED also is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. (For example, on February 3, 2018, it was reported that investigators with the Santa Rosa Fire Department had completed their investigation of two small fires that reportedly destroyed two homes and damaged one outbuilding and had concluded that the Utility's facilities, along with high wind and other factors, contributed to those fires.) It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

As of January 31, 2018, the Utility had submitted 22 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire has identified a site as potentially involving the Utility's facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary, and does not reflect a determination of the causes of the fires. The investigations into the fires are ongoing.

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows" below.) In addition to such claims for property damage, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.



Given the preliminary stages of investigations and the uncertainty as to the causes of the fires, PG&E Corporation and the Utility do not believe a loss is probable at this time. However, it is reasonably possible that facts could emerge through the course of the various investigations that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in an accrued liability in the future, the amount of which could be material. PG&E Corporation and the Utility currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur, given the preliminary stages of the investigations and the uncertainty regarding the extent and magnitude of potential damages. On January 31, 2018, the California Department of Insurance issued a press release

announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion estimated in respect of the wildfires that occurred in October 2017, depending on the extent of the damage in connection with such fire or fires. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

PG&E Corporation and the Utility also are the subject of a still increasing number of lawsuits that have been filed against PG&E Corporation and the Utility in Sonoma, Napa and San Francisco Counties' Superior Courts, several of which seek to be certified as class actions. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, two derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively. PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $800 million. If the Utility were to be found liable for one or more fires, the Utility's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires.

In addition, it could take a number of years before the Utility's final liability is known and the Utility could apply for cost recovery. The Utility may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. Further, SB 819, introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities from recovering costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the utility did not reasonably construct, maintain, manage, control, or operate the facilities. PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See "If the Utility is unable to recover all or a significant portion of its excess costs in connection with the Northern California wildfires and the Butte fire through ratemaking mechanisms, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected" below.)

Losses in connection with the wildfires would likely require PG&E Corporation and the Utility to seek financing, which may not be available on terms acceptable to PG&E Corporation or the Utility, or at all, when required. (See "Risks Related to Liquidity and Capital Requirements" below.)



As of December 31, 2017, neither PG&E Corporation nor the Utility has accrued a liability with respect to the Northern California wildfires. If PG&E Corporation and the Utility were to determine that it is both probable that a

loss has occurred and the amount of loss can be reasonably estimated, a liability would be recorded consistent with applicable accounting principles and as described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. As noted above, to the extent that such determination is made and a liability is accrued with respect to the Northern California wildfires, the amount of such liability accrual may be substantial. To the extent not offset by insurance recoveries determined to be similarly probable and estimable, the liability would reduce the balance sheet equity of PG&E Corporation and the Utility, which could adversely impact the Utility's ability to maintain its CPUC-authorized capital structure of 52% equity and 48% debt and preferred stock, and which could also adversely impact PG&E Corporation's and the Utility's credit ratings and their ability to declare and pay dividends, efficiently raise capital, comply with financial covenants, and meet financial obligations. (See "PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings" below.)

Uncertainties relating to and market perception of these matters and the disclosure of findings regarding these matters over time, also could continue or increase volatility in the market for PG&E Corporation's common stock and other securities, and for the securities of the Utility, and materially affect the price of such securities.

***PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the Butte fire.***

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a gray pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

In connection with the Butte fire, complaints have been filed against the Utility, currently involving approximately 3,770 individual plaintiffs representing approximately 2,030 households and their insurance companies. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. The number of individual complaints and plaintiffs may still increase in the future, because the statute of limitations for property damages in connection with the Butte fire has not yet expired. (The statute of limitations for personal injury in connection with the Butte fire has expired.) The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint seeking to recover $87 million for its costs incurred in connection with the Butte fire, and in May 2017, the OES indicated that it intends to bring a claim against the Utility that the OES estimated in the approximate amount of $190 million. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court or jury would agree with the Utility.

The Utility currently believes that it is probable that it will incur a loss of at least $1.1 billion, increased from the $750 million previously estimated as of December 31, 2016 in connection with the Butte fire. While this amount includes the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Utility still does not have sufficient information to reasonably estimate the probable loss it may have for these additional claims. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See Note 13 to the Consolidated Financial Statements in Item 8.)

***If the Utility is unable to recover all or a significant portion of its excess costs in connection with the Northern California wildfires and the Butte Fire through ratemaking mechanisms, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.***

Through December 31, 2017, the amounts accrued in connection with claims relating to the Butte fire have exceeded the Utility's liability insurance coverage. While the Utility filed an application with the CPUC requesting approval to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of

wildfire costs that have not otherwise been recovered through insurance or other mechanisms, the Utility cannot predict the outcome of this proceeding. (See “Regulatory Matters - Application to Establish a Wildfire Expense Memorandum Account” in Item 7. MD&A.)



In addition, there can be no assurance that the Utility will be allowed to recover costs recorded in WEMA, if approved, in the future. While the CPUC previously approved WEMA tracking accounts for San Diego Gas & Electric Company in 2010, in December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC’s prudent manager standard. That determination is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison.

Additionally, SB 819 introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities’ recovery of costs in excess of insurance resulting from damages caused by such utilities’ facilities, if the CPUC determines that the Utility did not reasonably construct, maintain, manage, control, or operate the facilities.

PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover all or a significant portion of costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material effect on PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows.

***The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity and cash flows.***

California law includes a doctrine of inverse condemnation that is routinely invoked in California for wildfire damages. Inverse condemnation imposes strict liability (including liability for attorneys’ fees) for damages as a result of the design, construction and maintenance of utility facilities, including utilities’ electric transmission lines. Courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Plaintiffs have asserted the doctrine of inverse condemnation in lawsuits related to the Northern California and Butte fires, and it is possible that plaintiffs could be successful in convincing courts to apply this doctrine in these or other litigations. For example, on June 22, 2017, the Superior Court for the County of Sacramento found that the doctrine of inverse condemnation applies to the Utility with respect to the Butte fire. Although the Utility has filed a renewed motion for a legal determination of inverse condemnation liability, there can be no assurance that the Utility will be successful in its arguments that the doctrine of inverse condemnation does not apply in the Butte fire or other litigation against PG&E Corporation or the Utility.

Furthermore, a court could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. Although the imposition of liability is premised on the assumption that utilities have the ability to automatically recover these costs from their customers, there can be no guarantee that the CPUC would authorize cost recovery whether or not a previous court decision imposes liability on a utility under the doctrine of inverse condemnation. In December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC’s prudent manager standard. That determination is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison.

If PG&E Corporation or the Utility were to be found liable for damage under the doctrine of inverse condemnation, but is unable to secure a cost recovery decision from the CPUC to pay for such costs through increases in rates, the financial condition, results of operations, liquidity and cash flows of PG&E Corporation and the Utility would be materially affected by potential losses resulting from the impact of the Northern California wildfires. (See “PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions” and “PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the Butte fire” above.)

**Risks Related to the Outcome of Other Enforcement Matters, Investigations, and Regulatory Proceedings**

***The Utility is subject to extensive regulations and the risk of enforcement proceedings in connection with such regulations, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the outcomes of the CPUC's investigative enforcement proceedings against the Utility, other known enforcement matters, and other ongoing state and federal investigations and requests for information. The Utility could incur material costs and fines in connection with compliance with penalties from closed investigations or enforcement actions or in connection with future investigations, citations, audits, or enforcement actions.***

The Utility is subject to extensive regulations, including federal, state and local energy, environmental and other laws and regulations, and the risk of enforcement proceedings in connection with such regulations. The Utility could incur material charges, including fines and other penalties, in connection with the ex parte OII, safety culture OII, and the CPUC's SED investigations, including the SED's investigations of the Yuba City incident, which arose from a residential structure fire in Yuba City, California, in January 2017, that resulted in the collapse of a house and injuries to two persons inside the house, or other current and future investigations. The SED could launch investigations at any time on any issue it deems appropriate.

The SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED also has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The SED also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged. Historically, the SED has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. While it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations, such fines or penalties could be significant and materially affect PG&E Corporation's and the Utility's liquidity and results of operations. (See Note 13 to the Consolidated Financial Statements in Item 8.)

The Utility also is a target of a number of investigations. In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility also is unable to predict the outcome of, or costs and expenses associate with, pending investigations, including whether any charges will be brought against the Utility.

If these investigations result in enforcement action against the Utility, the Utility could incur additional fines or penalties and, in the event of a judgment against the Utility, suffer further ongoing negative consequences. For example, on April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "San Bruno Penalty Decision"). The San Bruno Penalty Decision requires the SED to review the Utility's gas transmission operations (including the Utility's compliance with the remedies ordered by the San Bruno Penalty Decision) and to perform annual audits of the Utility's record-keeping practices for a minimum of ten years. The SED could impose fines on the Utility or require the Utility to incur unrecoverable costs, or both, based on the outcome of these future audits. Furthermore, a negative outcome in any of these investigations, or future enforcement actions, could negatively affect the outcome of future ratemaking and regulatory proceedings to which the Utility may be subject; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations. (See also "PG&E Corporation's and the Utility's future financial results could be materially affected by the conviction of the Utility in the federal criminal proceeding and by the debarment proceeding" below.)

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and resource adequacy requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; compliance with CPUC general orders or other applicable CPUC decisions or regulations; federal electric reliability standards; and environmental compliance. For example, despite the Utility's system-wide survey of its transmission pipelines, carried out in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way, the SED could impose fines on the Utility in the

future based on the Utility's failure to continuously survey its system and remove encroachments. CPUC staff could also impose penalties on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.



***PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected in the event of non-compliance with the terms of probation and by the outcome of the debarment proceeding.***

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court issued a judgment of conviction against the Utility. The court sentenced the Utility to a five-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service.

The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility has retained a third-party monitor at the Utility's expense. The goal of the monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations, and to maintain effective ethics, compliance and safety related incentive programs on a Utility-wide basis.

The Utility could incur material costs and additional penalties, not recoverable through rates, in the event of non-compliance with the terms of its probation and in connection with the monitorship (including but not limited to costs resulting from recommendations of the monitor).

Since 2015, the Utility has also been the subject of a DOI inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs, citing the San Bruno explosion, and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. On December 21, 2016, the Utility and the DOI entered into an interim administrative agreement that reflects the DOI's determination that the Utility remains eligible to contract with federal government agencies while the DOI determines whether any further action is necessary to protect the federal government's business interests. If the DOI determines that the Utility's compliance and ethics program is not generally effective in preventing and detecting criminal conduct, the Utility may be required to enter into an amended administrative agreement and implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third-party monitor(s).

The Utility's conviction and the outcome of probation and the debarment proceeding could harm the Utility's relationships with regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, they could negatively affect the outcome of future ratemaking and regulatory proceedings, for example, by enabling parties to argue that the Utility should not be allowed to recover costs that the parties allege are somehow related to the criminal charges on which the Utility was found guilty. They could also result in increased regulatory or legislative scrutiny with respect to various aspects of how the Utility's business is conducted or organized. (See "Enforcement and Litigation Matters" in Item 7. MD&A.)

***PG&E Corporation's and the Utility's financial results primarily depend on the outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its operating expenses and capital expenditures so that it is able to earn its authorized rate of return in a timely manner.***

As a regulated entity, the Utility's rates are set by the CPUC or the FERC on a prospective basis and are generally designed to allow the Utility to collect sufficient revenues to recover reasonable costs of providing service, including a return on its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe,

reliable, and affordable electric and gas services. Further, the increasing amount of Reliability Must Run ("RMR") electric generation in the CAISO could increase the Utility's costs of procuring capacity needed for reliable service to its customers.



In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial results could be materially affected if the Utility's actual costs to safely and reliably serve its customers differ from authorized or forecast costs. The Utility may incur additional costs for many reasons including changing market circumstances, unanticipated events (such as storms, fires, accidents, or catastrophic or other events affecting the Utility's operations), or compliance with new state laws or policies. Although the Utility may be allowed to recover some or all of the additional costs, there may be a substantial time lag between when the Utility incurs the costs and when the Utility is authorized to collect revenues to recover such costs. Alternatively, the CPUC or the FERC may disallow costs that they determine were not reasonably or prudently incurred by the Utility.

The Utility also is required to incur costs to comply with legislative and regulatory requirements and initiatives, such as those relating to the development of a state-wide electric vehicle charging infrastructure, the deployment of distributed energy resources, implementation of demand response and customer energy efficiency programs, energy storage and renewable energy targets, underground gas storage, and the construction of the California high-speed rail project. The Utility's ability to recover costs, including its investments, associated with these and other legislative and regulatory initiatives will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect a lower customer demand for the Utility's electricity and natural gas services.

***PG&E Corporation's and the Utility's financial results depend upon the Utility's continuing ability to recover "pass-through" costs, including electricity and natural gas procurement costs, from customers in a timely manner. The CPUC may disallow procurement costs for a variety of reasons. In addition, the Utility's ability to recover these costs could be affected by the loss of Utility customers and decreased new customer growth, if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch" and prudent administration of power purchase agreements in compliance with its CPUC-approved long-term procurement plan. The CPUC could disallow procurement costs incurred by the Utility if the CPUC determines that the Utility did not comply with these principles or if the Utility did not comply with its procurement plan.

Further, the contractual prices for electricity under the Utility's current or future power purchase agreements could become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to adverse economic conditions or the loss of the Utility's customers to other retail providers. In particular, the Utility will incur additional costs to procure renewable energy to meet the higher targets established by California SB 350 that became effective on January 1, 2016. Despite the CPUC's current approval of the contracts, the CPUC could disallow contract costs in the future if it determines that the terms of such contracts, including price, do not meet the CPUC reasonableness standard.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by whether the CAISO wholesale electricity market continues to function effectively. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended which could result in excessive market prices. The CPUC could prohibit the Utility from passing through the higher costs of electricity to customers. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's then-newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreasing bundled load that occurs through municipalization of the Utility's facilities, an increase in the number of CCAs who provide electricity to their residents, and an increase in the number of consumers who become direct access customers of alternative generation providers. (See "Competition in the Electricity Industry" in Item 1.)

As the number of bundled customers (i.e., those customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase as the Utility would have a smaller customer base from which to recover certain procurement costs. Although the Utility is permitted to collect non-bypassable charges for above market generation-related costs incurred on behalf of former customers, the charges may not be sufficient for the Utility to fully recover these costs. In addition, the Utility's ability to collect non-bypassable charges has been, and may continue to be, challenged by certain customer groups. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer NEM, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pressure on remaining customers. New rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers are required to pay an interconnection fee, comply with time of use rates, and are required to pay certain non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. Remaining customers may incur significantly higher bills due to an increase in customers seeking alternative energy providers. The CPUC has indicated that it intends to revisit these rules in 2019.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments. If the number of the Utility's customers decreases or grows at a slower rate than anticipated, the Utility's level of authorized capital investment could decline as well, leading to a slower growth in rate base and earnings. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, and cash flows.

The CPUC has begun to implement rate reform to allow residential electric rates to more closely reflect the utilities' actual costs of providing service and decrease cross-subsidization among customer classes. Many aspects of rate reform are not yet finalized, including time-of-use rates and whether the utilities can impose a fixed charge on certain customers.

Further, changes in commodity prices also may have an adverse effect on the Utility's ability to timely recover its operating costs and earn its authorized ROE. Although the Utility generally recovers its electricity and natural gas procurement costs from customers as "pass-through" costs, a significant and sustained rise in commodity prices could create overall rate pressures that make it more difficult for the Utility to recover its costs that are not categorized as "pass-through" costs. To relieve some of this upward rate pressure, the CPUC could authorize lower revenues than the Utility requested or disallow full cost recovery.

If the Utility is unable to recover a material portion of its procurement costs and/or if the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, the wide deployment of distributed generation, and the development of new electricity generation and energy storage technologies, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

**Risks Related to Liquidity and Capital Requirements**

***The outcome or market perception of the investigations and litigation in connection with the Northern California wildfires, and the outcome or market perception of other litigation and enforcement matters, could reduce or eliminate PG&E Corporation's and the Utility's access to the capital markets and other sources of financing, which could have a material adverse effect on PG&E Corporation and the Utility.***

PG&E Corporation's and the Utility's liquidity is dependent on many factors, including access to the capital markets and availability under their revolving credit facilities and commercial paper programs. PG&E Corporation's and the Utility's ability to access the capital markets, the ability to borrow under their loan financing arrangements, including their revolving credit facilities, and the terms and rates of future financings, as well as the credit ratings of PG&E Corporation and the Utility and their respective debt facilities, could be materially affected by the outcome or market perception of the matters discussed in this 2017 Form 10-K under "Northern California Wildfires" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. Liabilities that could be incurred as a result of the Northern California wildfires could adversely affect their ability to comply with the covenants in their financing arrangements, which could adversely affect the ability to borrow under the applicable facility or program.

Access by PG&E Corporation to the equity capital markets is also critical to maintaining the Utility's CPUC-authorized capital structure. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In the fiscal year ended December 31, 2017, PG&E Corporation issued $416 million in common stock and made equity contributions of $455 million to the Utility. PG&E Corporation forecasts it will need a material amount of equity in future years, including to support the Utility's capital expenditures. PG&E Corporation may also seek to issue additional equity to fund unrecoverable operating expenses and to pay claims, losses, fines and penalties that may be required by the outcome of enforcement matters and litigation, including in connection with the Northern California wildfires, and the outcome of the related CPUC and Cal Fire investigations.

If either PG&E Corporation or the Utility is unable to access the capital markets or to borrow under their respective loan financing arrangements or commercial paper programs, PG&E Corporation and the Utility's financial condition, results of operations, liquidity, and cash flows, could be materially affected.



***PG&E Corporation's and the Utility's ability to meet their debt service and other financial obligations and their ability to pay dividends depend on the Utility's earnings and cash flows. In addition, in December 2017, the Boards of Directors suspended dividends on PG&E Corporation's common stock and the Utility's preferred stock, as a result of which the price of PG&E Corporation's common stock and the ability of PG&E Corporation and the Utility to raise equity capital could be adversely affected.***

PG&E Corporation is a holding company with no revenue generating operations of its own. The Utility must use its resources to satisfy its own obligations, including the Utility's obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, unless suspended, and meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. Under the CPUC's rules applicable to utility holding companies, the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company and PG&E Corporation's Board of Directors must give "first priority" to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC has interpreted this "first priority" obligation to include the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." In addition, before the Utility can pay common stock dividends to PG&E Corporation, the Utility must maintain its authorized capital structure with an average 52% equity component.

If the Utility were required to pay a material amount of fines or incur material unrecoverable costs in connection with the Northern California wildfires, the Butte fire, the pending CPUC investigations, the terms of probation or monitorship, or other liabilities or enforcement matters, it would require incremental equity contributions from PG&E Corporation to restore its capital structure. PG&E Corporation common stock issuances used to fund such equity contributions could materially dilute earnings per share. (See "Liquidity and Financial Resources" in Item 7. MD&A). Further, if PG&E Corporation were required to infuse the Utility with significant capital or if the Utility were unable to distribute cash to PG&E Corporation, or both, PG&E Corporation may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend or meet other obligations.

In December 2017, the Boards of Directors of PG&E Corporation and the Utility suspended dividends on common stock of PG&E Corporation and preferred stock of the Utility due to uncertainty related to the causes and potential liabilities associated with the Northern California wildfires. The suspension of dividends could continue to materially affect the price of PG&E Corporation's common stock and adversely affect the ability of PG&E Corporation to raise additional equity capital. There can be no assurances as to when, if at all, the Board of Directors of PG&E Corporation and the Utility will determine to re-instate quarterly cash dividends on PG&E Corporation's common stock or the Utility's preferred stock.

***PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.***

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, and to pay fines that may be imposed in the future, as well as costs related to rights-of-way and legal and regulatory costs. PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation's and the Utility's credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including pending or anticipated litigation, the pending Cal Fire and CPUC investigations and CPUC ratemaking proceedings, and by the December 20, 2017 decision of the Boards of Directors of PG&E Corporation and the Utility to suspend dividends, as well as the perceived impact of all such matters on PG&E Corporation's and the Utility's financial condition, whether or not such perception is accurate. On December 21, 2017, Moody's Investor Services and on December 22, 2017, Standard & Poor's Global Ratings, each placed all of the ratings of PG&E Corporation and the Utility under review for downgrade, and Standard & Poor's Global Ratings additionally lowered its ratings on the Utility's preferred stock. If PG&E Corporation's or the Utility's credit ratings were to be downgraded or the ratings on the Utility's preferred stock are further downgraded, in particular to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market and additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory

environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under "Enforcement and Litigation Matters" in Item 3. Legal Proceedings and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. The negative publicity and the uncertainty about the outcomes of these matters may undermine confidence in management's ability to execute its business strategy and restore a constructive regulatory environment, which could adversely impact PG&E Corporation's stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.



**Risks Related to Operations and Information Technology**

***The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. (See "Electric Utility Operations" and "Natural Gas Utility Operations" in Item 1. Business.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives, and the CPUC approved retirement of Diablo Canyon by 2024 and 2025. The Utility's ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond the Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;
- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electrical black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees or the public, environmental damage, or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wild land fire or natural gas explosion);
- inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;
- operator or other human error;
- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;
- construction performed by third parties that damages the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines;

- the release of hazardous or toxic substances into the air, water, or soil, including, for example, gas leaks from natural gas storage facilities; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and
- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war.



The occurrence of any of these events could interrupt fuel supplies; affect demand for electricity or natural gas; cause unplanned outages or reduce generating output; damage the Utility's assets or operations; damage the assets or operations of third parties on which the Utility relies; damage property owned by customers or others; and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, and to compensate third parties.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities or the construction or demolition or facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions.

Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

***The Utility's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events, or may not be available at a reasonable cost, or available at all.***

The Utility has experienced increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from the Utility's ordinary operations. PG&E Corporation, the Utility or its contractors and customers may experience coverage reductions and/or increased wildfire insurance costs in future years. No assurance can be given that future losses will not exceed the limits of the Utility's insurance coverage. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

As a result of the potential application of a strict liability standard under the doctrine of inverse condemnation, recent losses recorded by insurance companies, the risk of increase of wildfires including as a result of the ongoing drought, the Northern California wildfires, and the Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at comparable cost and terms as the Utility's current insurance coverage, or at all. In addition, the Utility is unable to predict whether it would be allowed to recover in rates the increased costs of insurance or the costs of any uninsured losses.

Future insurance coverage may not be available at rates and on terms as favorable as the Utility's current insurance coverage or may not be available at all. If the amount of insurance is insufficient or otherwise unavailable, or if the Utility is unable to recover in rates the costs of any uninsured losses, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***The electric power industry is undergoing significant change driven by technological advancements and a decarbonized economy, which could materially impact the Utility's operations, financial condition, and results of operations.***

The electric power industry is undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. California's environmental policy objectives are accelerating the pace and scope of the industry change. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policymakers notwithstanding a recent change in the federal approach to such matters. California utilities are experiencing increasing deployment by customers and third parties of DERs, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and demand response technologies. This growth will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity, increase the grid's capacity, and interconnect DERs.

In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, EV infrastructure and state infrastructure modernization (e.g. rail and water projects).

To this end, the CPUC is conducting proceedings to: evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of DERs; consider future grid modernization and grid reinforcement investments; evaluate if traditional grid investments can be deferred by DERs, and if feasible, what, if any, compensation to utilities would be appropriate for enabling those investments; and clarify the role of the electric distribution grid operator. The CPUC has also recently opened proceedings regarding the creation of a shared database or statewide census of utility poles and conduits in California and increased access by communications providers to utility rights-of-way. This proceeding could require utilities to invest significant resources into inspecting poles and conduits, limit available capacity in existing rights-of-way, or impose other requirements on utilities facilities. The Utility is unable to predict the outcome of these proceedings.

In addition, the CPUC has held discussions on potential changes to California's electricity market. On May 19, 2017, California energy companies, along with other stakeholders, discussed customer choice and the future of the state's electricity industry at a CPUC "en banc" meeting. Specifically, the goal of the "en banc" was to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy and to lay out elements of a path forward to ensure that California achieves its reliability, affordability, equity, and carbon reduction imperatives while recognizing the important role that technology and customer preferences will play in shaping this future. While the CPUC had indicated its intent to open a proceeding related to customer choice, the Utility is unable to predict whether that remains the CPUC's intent or the timing of any such proceeding.

The industry change, costs associated with complying with new regulatory developments and initiatives and with technological advancements, or the Utility's inability to successfully adapt to changes in the electric industry, could materially affect the Utility's operations, financial condition, and results of operations.

***A cyber incident, cyber security breach, severe natural event or physical attack on the Utility's operational networks and information technology systems could have a material effect on its business, financial condition, results of operations, liquidity, and cash flows.***

The Utility's electricity and natural gas systems rely on a complex, interconnected network of generation, transmission, distribution, control, and communication technologies, which can be damaged by natural events-such as severe weather or seismic events-and by malicious events, such as cyber and physical attacks. Private and public entities, such as the North American Electric Reliability Corporation, and U.S. Government Departments, including the Departments of Defense, Homeland Security and Energy, and the White House, have noted that cyber-attacks targeting utility systems are increasing in sophistication, magnitude, and frequency. The Utility's operational networks also may face new cyber security risks due to modernizing and interconnecting the existing infrastructure with new technologies and control systems. Any failure or decrease in the functionality of the Utility's operational networks could cause harm to the public or employees, significantly disrupt operations, negatively impact the Utility's ability to safely generate, transport, deliver and store energy and gas or otherwise operate in the most safe and efficient manner or at all, and damage the Utility's assets or operations or those of third parties.

The Utility also relies on complex information technology systems that allow it to create, collect, use, disclose, store and otherwise process sensitive information, including the Utility's financial information, customer energy usage and billing information, and personal information regarding customers, employees and their dependents, contractors, and other individuals. In addition, the Utility often relies on third-party vendors to host, maintain, modify, and update its systems, and to provide other services to the Utility or the Utility's customers. These third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience security incidents or inadequate security measures. Any incidents or disruptions in the Utility's information technology systems could impact the Utility's ability to track or collect revenues and to maintain effective internal controls over financial reporting.

The Utility and its third party vendors have been subject to, and will likely continue to be subject to attempts to gain unauthorized access to the Utility's information technology systems or confidential data (including information about customers and employees), or to disrupt the Utility's operations. None of these attempts or breaches has individually or in the aggregate resulted in a security incident with a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent the unauthorized access to its operational networks, information technology systems or data, or the disruption of its operations. Such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, penalties for violation of applicable privacy laws, investigations, and regulatory actions that could result in fines and penalties, loss of customers and

harm to PG&E Corporation's and the Utility's reputation, any of which could have a material adverse effect on PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents. However, there is no guarantee that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.



***The operation and decommissioning of the Utility's nuclear generation facilities expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire.***

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon units by 2024 and 2025. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before their respective licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial condition, results of operations, liquidity, and cash flows.

In addition, in order to retain highly skilled personnel necessary to safely operate Diablo Canyon during the remaining years of operations, the Utility will incur costs in connection with (i) an employee retention program to ensure adequate staffing levels at Diablo Canyon, and (ii) an employee retraining and development program, to facilitate redeployment of a portion of Diablo Canyon personnel to the decommissioning project and elsewhere in the company. In its January 11, 2018 decision, the CPUC authorized rate recovery up to $211.3 million (compared with the $352.1 million requested by the Utility) for an employee retention program, but there can be no assurance that the Utility will be successful in retaining highly skilled personnel under such program.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See "Regulatory Environment" in Item 1. Business.) If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon's two nuclear generation units before their respective licenses expire in 2024 and 2025. At December 31, 2017, the Utility's unrecovered investment in Diablo Canyon was $1.7 billion.

On June 28, 2016 the California State Lands Commission approved an extension of the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon, to run concurrently with Diablo Canyon's current operating licenses. The Utility will be required to obtain an additional lease extension from the State Lands Commission to cover the period of time necessary to decommission the facility. The State Lands Commission and California Coastal Commission will evaluate appropriate environmental mitigation and development conditions associated with the decommissioning project, the costs of which could be substantial.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2: Summary of Significant Accounting Policies - Asset Retirement Obligations of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear

decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.



***The Utility purchases its nuclear fuel assemblies from a sole source, Westinghouse. If Westinghouse experiences business disruptions as a result of Chapter 11 proceedings or its pending acquisition by Brookfield, the Utility could experience disruptions in nuclear fuel supply, and delays in connection with its Diablo Canyon outages and refuelings.***

The Utility purchases its nuclear fuel assemblies for Diablo Canyon from a sole source, Westinghouse. The Utility also stores nuclear fuel inventory at the Westinghouse fuel fabrication facility. In addition, Westinghouse provides the Utility with Diablo Canyon outage support services, nuclear fuel analysis, original equipment manufacturer engineering and parts support. On March 29, 2017, Westinghouse filed for Chapter 11 protection in the United States Bankruptcy Court, Southern District of New York. On January 4, 2018, Westinghouse announced that it has agreed to be acquired by Brookfield Business Partners L.P. Westinghouse also indicated that its acquisition by Brookfield is expected to close in the third quarter of 2018, subject to Bankruptcy Court approval and customary closing conditions including, among others, regulatory approvals. In the event that Westinghouse experiences business disruptions in its nuclear fuel business as a result of bankruptcy proceedings, its pending acquisition by Brookfield, or otherwise, the Utility could experience issues with its nuclear fuel supply and delays in connection with Diablo Canyon refueling outages.

Diablo Canyon's Unit 2 refueling outage will occur in the first quarter of 2018 and the required fuel for that outage has been delivered. The next Unit 1 refueling outage is expected to occur in the first quarter of 2019 and the fuel for that outage has not yet been fabricated. If Westinghouse were to fail to deliver nuclear fuel or provide outage support to the Utility, the Utility's operation of Diablo Canyon would be adversely affected. PG&E Corporation and the Utility also could experience additional costs, including decreased electricity market revenues, in the event that one or both Diablo Canyon units are unable to operate. There can be no assurance that any such additional costs would be recoverable in the rates the Utility is permitted to recover from its customers. Furthermore, the Utility currently is not able to estimate the nature or amount of additional costs and expenses that it might incur in connection with the uncertainties surrounding Westinghouse but such costs and expenses could be material.

***For certain critical technologies, products and services, the Utility relies on a limited number of suppliers and, in some cases, sole suppliers. In the event these suppliers are unable to perform, the Utility could experience delays and disruptions in its operations while it transitions to alternative plans or suppliers.***

The Utility relies on a limited number of sole source suppliers for certain of its technologies, products and services. Although the Utility has long-term agreements with such suppliers, if the suppliers are unable to deliver these technologies, products or services, the Utility could experience delays and disruptions while it implements alternative plans and makes arrangements with acceptable substitute suppliers. As a result, the Utility's business, financial condition, and results of operations could be significantly affected. As an example, the Utility relies on Silver Spring Networks, Inc. and Aclara Technologies LLC as suppliers of proprietary SmartMeter™ devices and software, and of managed services, utilized in its advanced metering system that collects electric and natural gas usage data from customers. If these suppliers encounter performance difficulties or are unable to supply these devices or maintain and update their software, or provide other services to maintain these systems, the Utility's metering, billing, and electric network operations could be impacted and disrupted.

**Risks Related to Environmental Factors**

***Severe weather conditions, extended drought and shifting climate patterns could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, and cash flows.***

Extreme weather, extended drought and shifting climate patterns have intensified the challenges associated with wildfire management in California. Environmental extremes, such as drought conditions followed by periods of wet weather, can drive additional vegetation growth (which then fuel any fires) and influence both the likelihood and severity of extraordinary wildfire events. In California, over the past five years, inconsistent and extreme precipitation, coupled with more hot summer days, have increased the wildfire risk and made wildfire outbreaks increasingly difficult to manage. In particular, the risk posed by wildfires has increased in the Utility's service area (the Utility has approximately 82,000 distribution overhead circuit miles and 18,000 transmission overhead circuit miles) as a result of an extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases due to record rainfall following the drought, among other environmental factors. Other contributing factors

include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk.

Severe weather events, including wildfires and other fires, storms, tornadoes, floods, drought, earthquakes, tsunamis, pandemics, solar events, electromagnetic events, or other natural disasters such as wildfires, could result in severe business disruptions, prolonged power outages, property damage, injuries or loss of life, significant decreases in revenues and earnings, and/or significant additional costs to PG&E Corporation and the Utility. Any such event could have a material effect on PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, and cash flows. If the Utility is unable to recover its wildfire costs, due to the reasons described in the risk factors related to the Northern California fires, Butte fire, the doctrine of inverse condemnation, and insurance limitations above, or for other reasons, its financial condition, results of operations, liquidity, and cash flows could be materially affected.



Further, the Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns, rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. As a result, the Utility's hydroelectric generation could change and the Utility would need to consider managing or acquiring additional generation. If the Utility increases its reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including generation and electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, or compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial results.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, and orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. (For more information, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. (See "Environmental Regulation" in Item 1. and Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's

financial results. Their financial results also can be materially affected by changes in estimated costs and by the extent to which actual remediation costs differ from recorded liabilities.

***State climate policy requires reductions in greenhouse gases of 40% by 2030 and 80% by 2050. Various proposals for addressing these reductions have the potential to reduce natural gas usage and increase natural gas costs. The future recovery of the increased costs associated with compliance is uncertain.***

The CARB is the state's primary regulator for GHG emission reduction programs. Natural gas providers have been subject to compliance with CARB's Cap-and-Trade Program since 2015, and natural gas end-use customers have an increasing exposure to carbon costs under the Program through 2030 when the full cost will be reflected in customer bills. CARB's Scoping Plan also proposes various methods of reducing GHG emissions from natural gas. These include more aggressive energy efficiency programs to reduce natural gas end use, increased renewable portfolio standards generation in the electric sector reducing noncore gas load, and replacement of natural gas appliances with electric appliances, leading to further reduced demand. These natural gas load reductions may be partially offset by CARB's proposals to deploy natural gas to replace wood fuel in home heating and diesel in transportation applications. CARB also proposes a displacement of some conventional natural gas with above-market renewable natural gas. The combination of reduced load and increased costs could result in higher natural gas customer bills and a potential mandate to deliver renewable natural gas could lead to cost recovery risk.

**Other Risk Factors**

***The Utility may be required to incur substantial costs in order to obtain or renew licenses and permits needed to operate the Utility's business and the Utility may be subject to fines and penalties for failure to comply or obtain license renewal.***

The Utility must comply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility's hydroelectric generation facilities, and those issued by environmental and other federal, state and local governmental agencies. Many of the Utility's capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizations, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility.

If a license or permit is not renewed for a particular facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs. Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Utility's compliance costs. In particular, in connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has not been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, licenses, ordinances, or other requirements, or if the Utility cannot recover the increase in associated compliance and other costs in a timely manner, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***Poor investment performance or other factors could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. The performance of the debt and equity markets affects the value of plan assets and trust assets. A decline in the market value may increase the funding requirements for these plans and trusts. The cost of providing pension and other postretirement benefits is also affected by other factors, including interest rates used to measure the required minimum funding levels, the rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by the rates of return on trust assets, changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. (See Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in Item 8.) If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans or if actual nuclear decommissioning costs exceed the amount of nuclear decommissioning trust funds and the Utility is unable to recover the contributions or additional costs in rates, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility's workforce is aging and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements with the unions or if tentative new agreements are not ratified by their members. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.



PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceedings. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

***The Utility's business activities are concentrated in one region, as a result of which, its future performance may be affected by events and factors unique to California.***

The Utility's business activities are concentrated in Northern California. As a result, the Utility's future performance may be affected by events and economic factors unique to California or by regional regulation or legislation, for example the doctrine of inverse condemnation. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation and the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows" above.)



**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

**ITEM 2. PROPERTIES**

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under "Electric Utility Operations" and "Natural Gas Utility Operations." The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11 million square feet of real property, including 9 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire in 2022.

The Utility currently owns approximately 160,000 acres of land, including approximately 132,000 acres of watershed lands. In 2002 the Utility agreed to implement its "Land Conservation Commitment" ("LCC") to permanently preserve the six "beneficial public values" on all the watershed lands through conservation easements or equivalent protections, as well as to make approximately 70,000 acres of the watershed lands available for donation to qualified organizations. The six "beneficial public values" being preserved by the LCC include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Utility's goal is to implement all the transactions needed to implement the LCC by the end of 2022, subject to securing all required regulatory approvals.

**ITEM 3. LEGAL PROCEEDINGS**

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

**Order Instituting an Investigation into the Utility's Safety Culture**

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record

of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment.

On May 8, 2017, the CPUC President released the consultant's report, accompanied by a scoping memo and ruling. The scoping memo establishes a second phase in this OII in which the CPUC will evaluate the safety recommendations of the consultant that may lead to the CPUC's adoption of the recommendations in the report, in whole or in part. This phase of the proceeding will also consider all necessary measures, including, but not limited to, a potential reduction of the Utility's return on equity until any recommendations adopted by the CPUC are implemented. On November 17, 2017, the CPUC issued a phase two scoping memo and procedural schedule. The scoping memo directed the Utility and other parties to file testimony addressing a number of issues including adoption of the safety recommendations from the consultant, the Utility's implementation process for the safety recommendations of the consultant, the Utility's Board of Director's actions and initiatives related to safety culture and the consultant's recommendations, the Utility's corrective action program, and the Utility's response to certain specified safety incidents that occurred in 2013 through 2015. The Utility's testimony was submitted to the CPUC on January 8, 2018 and stated that the Utility agrees with all of the recommendations of the consultant and supports their adoption by the CPUC. Other parties' responsive testimony is due February 16, 2018, and the Utility's rebuttal is due February 23, 2018. On January 29, 2018, the CPUC modified the procedural schedule to allow more time for parties to better identify areas of agreement to reduce the number of issues that may require hearings.

PG&E Corporation and the Utility are unable to predict the outcome of this proceeding, including whether additional fines, penalties, or other ratemaking tools will ultimately be adopted by the CPUC, and whether the CPUC will require that a portion of return on equity for the Utility be dependent on making safety progress as the CPUC may define in this proceeding.



**Diablo Canyon Nuclear Power Plant**

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement was that the Central Coast Board renew Diablo Canyon's permit.

However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists to develop additional information on possible mitigation measures for Central Coast Board staff. In 2005, the Central Coast Board reviewed the scientists' draft report recommending several such mitigation measures, but no action was taken.

In 2010, the California Water Board adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The policy also provided for an alternative compliance approach for nuclear plants if certain criteria were met. As required by the policy, the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014. The report addressed feasibility, costs and timeframes to install alternative technologies at Diablo Canyon, such as cooling towers.

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. As required under the policy, the Utility paid an annual interim mitigation fee beginning in 2017, which it will continue to pay until operations cease in 2025. Additionally, the Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility and the Central Coast Board regarding the thermal component of the plant's once-through cooling discharge.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on the Utility's financial condition or results of operations.

**ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

**EXECUTIVE OFFICERS OF THE REGISTRANTS**

The following individuals serve as executive officers [1] of PG&E Corporation and/or the Utility, as of February 9, 2018. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| Geisha J. Williams | 56 | Chief Executive Officer and President, PG&E Corporation | March 1, 2017 to present |



| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| | | President, Electric | September 15, 2015 to February 28, 2017 |
| | | President, Electric Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Electric Operations | June 1, 2011 to August 16, 2015 |
| Nickolas Stavropoulos | 59 | President and Chief Operating Officer | March 1, 2017 to present |
| | | President, Gas | September 15, 2015 to February 28, 2017 |
| | | President, Gas Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Gas Operations | June 13, 2011 to August 16, 2015 |
| Jason P. Wells | 40 | Senior Vice President and Chief Financial Officer, PG&E Corporation | January 1, 2016 to present |
| | | Vice President, Business Finance | August 1, 2013 to December 31, 2015 |
| | | Vice President, Finance | October 1, 2011 to July 31, 2013 |
| John R. Simon | 53 | Executive Vice President and General Counsel, PG&E Corporation | March 1, 2017 to present |
| | | Executive Vice President, Corporate Services and Human Resources, PG&E Corporation | August 17, 2015 to February 28, 2017 |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | April 16, 2007 to August 16, 2015 |

| | | | |
|---|---|---|---|
| Karen A. Austin | 56 | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| Loraine M. Giammona | 50 | Senior Vice President and Chief Customer Officer | September 18, 2014 to present |
| | | Vice President, Customer Service | January 23, 2012 to September 17, 2014 |
| Patrick M. Hogan | 54 | Senior Vice President, Electric Operations | February 1, 2017 to present |
| | | Senior Vice President, Electric Transmission and Distribution | March 1, 2016 to January 31, 2017 |
| | | Vice President, Electric Strategy and Asset Management | September 8, 2015 to February 29, 2016 |
| | | Vice President, Electric Operations, Asset Management | November 18, 2013 to September 7, 2015 |
| | | Senior Vice President, Transmission and Distribution Engineering and Design, BC Hydro | October 2011 to November 2013 |
| Julie M. Kane | 59 | Senior Vice President, Chief Ethics and Compliance Officer, and Deputy General Counsel, PG&E Corporation and Pacific Gas and Electric Company | March 21, 2017 to present |
| | | Senior Vice President and Chief Ethics and Compliance Officer, PG&E Corporation and Pacific Gas and Electric Company | May 18, 2015 to March 20, 2017 |



| | | | |
|---|---|---|---|
| | | Vice President, General Counsel and Compliance Officer, North America, Avon Products, Inc. | September 30, 2013 to March 31, 2015 |
| | | Vice President, Ethics and Compliance, Novartis Corporation | January 1, 2010 to August 31, 2015 |
| Steven E. Malnight | 45 | Senior Vice President, Strategy and Policy, PG&E Corporation and Pacific Gas and Electric Company | March 1, 2017 to present |
| | | Senior Vice President, Regulatory Affairs | September 18, 2014 to February 28, 2017 |
| | | Vice President, Customer Energy Solutions | May 15, 2011 to September 17, 2014 |
| Dinyar B. Mistry | 56 | Senior Vice President, Human Resources and Chief Diversity Officer, PG&E Corporation and Pacific Gas and Electric Company | February 1, 2017 to present |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | June 1, 2016 to January 31, 2017 |
| | | Senior Vice President, Human Resources, Chief Financial Officer, and Controller | March 1, 2016 to May 31, 2016 |
| | | Senior Vice President, Human Resources and Controller, PG&E Corporation | March 1, 2016 to May 31, 2016 |

| | | | |
|---|---|---|---|
| | | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to February 28, 2016 |
| | | Vice President and Controller, PG&E Corporation | March 8, 2010 to February 28, 2016 |
| Jesus Soto, Jr. | 50 | Senior Vice President, Gas Operations | September 8, 2015 to present |
| | | Senior Vice President, Engineering, Construction and Operations | September 16, 2013 to September 8, 2015 |
| | | Senior Vice President, Gas Transmission Operations | May 29, 2012 to September 15, 2013 |
| Fong Wan | 56 | Senior Vice President, Energy Policy and Procurement, Pacific Gas and Electric Company | September 8, 2015 to present |
| | | Senior Vice President, Energy Procurement | October 1, 2008 to September 8, 2015 |
| David S. Thomason | 42 | Vice President, Chief Financial Officer, and Controller, Pacific Gas and Electric Company | June 1, 2016 to present |
| | | Vice President and Controller, PG&E Corporation | June 1, 2016 to present |
| | | Senior Director, Financial Forecasting and Analysis | March 2, 2015 to May 31, 2016 |
| | | Senior Director, Corporate Accounting | March 2, 2014 to March 1, 2015 |
| | | Senior Director, Financial Forecasting and Analysis | September 1, 2012 to March 1, 2014 |

(1) Ms. Williams, Mr. Stavropoulos, Mr. Wells, Mr. Simon, Ms. Kane, Mr. Malnight and Mr. Mistry are executive officers of both PG&E Corporation and the Utility. All other listed officers are executive officers of the Utility only.



# PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 1, 2018, there were 53,878 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and is traded under the symbol "PCG". The high and low closing prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth in the table entitled "Quarterly Consolidated Financial Data (Unaudited)" which appears after the Notes to the Consolidated Financial Statements in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock appears in "Liquidity and Financial Resources - Dividends" in Item 7. MD&A and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

***Sales of Unregistered Equity Securities***

PG&E Corporation made equity contributions to the Utility totaling $50 million during the quarter ended December 31, 2017. PG&E Corporation did not make any sales of unregistered equity securities during 2017 in reliance on an exemption from registration under the Securities Act of 1933, as amended.

***Issuer Purchases of Equity Securities***

During the quarter ended December 31, 2017, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. Also, during the

quarter ended December 31, 2017, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.



## ITEM 6. SELECTED FINANCIAL DATA

| (in millions, except per share amounts) | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,135 | $ 17,666 | $ 16,833 | $ 17,090 | $ 15,598 |
| Operating income | 2,956 | 2,177 | 1,508 | 2,450 | 1,762 |
| Net income | 1,660 | 1,407 | 888 | 1,450 | 828 |
| Net earnings per common share, basic [(1)] | 3.21 | 2.79 | 1.81 | 3.07 | 1.83 |
| Net earnings per common share, diluted | 3.21 | 2.78 | 1.79 | 3.06 | 1.83 |
| Dividends declared per common share [(2)] | 1.55 | 1.93 | 1.82 | 1.82 | 1.82 |
| **At Year-End** | | | | | |
| Common stock price per share | $ 44.83 | $ 60.77 | $ 53.19 | $ 53.24 | $ 40.28 |
| Total assets | 68,012 | 68,598 | 63,234 | 60,228 | 55,693 |
| Long-term debt (excluding current portion) | 17,753 | 16,220 | 15,925 | 15,151 | 12,805 |
| Capital lease obligations (excluding current portion) [(3)] | 18 | 31 | 49 | 69 | 90 |
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,138 | $ 17,667 | $ 16,833 | $ 17,088 | $ 15,593 |
| Operating income | 2,900 | 2,181 | 1,511 | 2,452 | 1,790 |
| Income available for common stock | 1,677 | 1,388 | 848 | 1,419 | 852 |
| **At Year-End** | | | | | |
| Total assets | 67,884 | 68,374 | 63,037 | 59,964 | 55,137 |
| Long-term debt (excluding current portion) | 17,403 | 15,872 | 15,577 | 14,799 | 12,805 |
| Capital lease obligations (excluding current portion) [(3)] | 18 | 31 | 49 | 69 | 90 |

(1) See "Overview - Summary of Changes in Net Income and Earnings per Share" in Item 7. MD&A.

(2) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources - Dividends" in Item 7. MD&A and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 in Item 8.

(3) The capital lease obligations amounts are included in noncurrent liabilities - other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility's base revenue requirements are set by the CPUC in its GRC and GT&S rate case and by the FERC in its TO rate cases based on forecast costs. Differences between forecast costs and actual costs can occur for numerous reasons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. Generally, differences between actual costs and forecast costs affect the Utility's ability to earn its authorized return (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations below). However, for certain operating costs, such as costs associated with pension and other employee benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). The Utility also collects revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, such as the costs to procure electricity or natural gas for its customers. Therefore, although these costs can fluctuate, they generally do not impact net income (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). See "Ratemaking Mechanisms" in Item 1 for further discussion.

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the way that they progressed. The CPUC's SED is also conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

PG&E Corporation and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. See Item 1A. Risk Factors.

**Tax Cuts and Jobs Act of 2017**

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and eliminated bonus depreciation for utilities.

The Tax Act also required PG&E Corporation and the Utility to re-measure existing deferred income tax assets and liabilities to reflect the lower federal tax rate. During the three months and year ended December 31, 2017, PG&E Corporation, on a consolidated basis, recorded a one-time provisional tax expense of $147 million to reflect the transitional impacts of the Tax Act. Of this amount, $83 million is attributable to the re-measurement of PG&E Corporation's net deferred tax asset comprised primarily of net operating loss carry-forwards and compensation-related items. The remaining $64 million is related to the re-measurement of the Utility's deferred taxes not reflected in authorized revenue requirements, such as disallowed plant. The Utility also recorded a provisional $5.7 billion re-measurement of its deferred tax balances (related to flow-through and normalized timing differences for plant-related items) which was offset by a change from a net deferred income tax regulatory asset to a net regulatory liability. The net deferred income tax regulatory liability will be refunded to customers over the regulatory lives of the related assets. The final transition impacts of the Tax Act may materially vary from the above recorded amounts due to, among other things, future regulatory decisions from the CPUC that could differ from the Utility's determination of how the impacts of the Tax Act are allocated between customers and shareholders.

As a result of the Tax Act, the Utility intends to file by the end of March 2018 (i) revised revenue requirements and rate base in its 2017 GRC (for years 2018 and 2019) and 2015 GT&S rate case (for 2018) as well as a proposed implementation plan in connection thereto, and (ii) revised revenue requirement and rate base forecast in its 2019 GT&S rate case. The Utility is unable to predict the timing and outcome of the CPUC decision in connection with such filings.

On an aggregate basis, the Utility anticipates an annual reduction to revenue requirements of approximately $500 million starting in 2018, and incremental increases to rate base of approximately $500 million in 2018 and $800 million in 2019 as a result of the Tax Act. The estimated benefit to customers is driven by the lower federal income tax rate applied to future earnings and the return of excess deferred income taxes. These benefits are partially offset by earnings on higher rate base and lower tax benefits from flow-through items.

In addition to this reduction in future revenue requirements, the Tax Act is expected to accelerate when PG&E Corporation resumes paying federal taxes, primarily due to the elimination of bonus depreciation; although future taxes are expected to be lower due to the lower federal tax rate. PG&E Corporation now expects to pay federal taxes starting in 2020, although that timing would be impacted by any significant changes to future results of operations. Additionally, because the revenue reduction is expected to precede the reduction in federal income tax payments, PG&E Corporation's and the Utility's operating cash flows will be negatively impacted resulting in additional financing needs.

**Summary of Changes in Net Income and Earnings per Share**

The tables below include a summary reconciliation of PG&E Corporation's consolidated income available for common shareholders and EPS to earnings from operations and EPS based on earnings from operations for the three months and twelve months ended December 31, 2017 compared to the three months and twelve months ended December 31, 2016 and a summary reconciliation of the key drivers of PG&E Corporation's earnings from operations and EPS based on earnings from operations for the three months and twelve months ended December 31, 2017 compared to the three months and twelve months ended December 31, 2016. "Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

| | Three Months Ended December 31, | | | | Year Ended December 31, | | | |
|---|---|---|---|---|---|---|---|---|
| (in millions, except per share amounts) | Earnings | | Earnings per Common Share (Diluted) | | Earnings | | Earnings per Common Share (Diluted) | |
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| **PG&E Corporation's Earnings on a GAAP basis** | **$ 114** | **$ 692** | **$ 0.22** | **$ 1.36** | **$ 1,646** | **$ 1,393** | **$ 3.21** | **$ 2.78** |
| Items Impacting Comparability: (1) | | | | | | | | |
| Tax Cuts and Jobs Act transition impact (2) | 147 | - | 0.29 | - | 147 | - | 0.29 | - |
| Northern California wildfire-related costs (3) | 49 | - | 0.09 | - | 49 | - | 0.09 | - |
| Butte fire-related costs, net of insurance (4) | 9 | 27 | 0.02 | 0.05 | 36 | 137 | 0.07 | 0.27 |
| Pipeline related expenses (5) | 7 | 20 | 0.01 | 0.04 | 52 | 67 | 0.10 | 0.13 |
| Legal and regulatory related expenses (6) | 1 | 11 | - | 0.02 | 6 | 43 | 0.01 | 0.09 |
| Fines and penalties (7) | - | 101 | - | 0.20 | 47 | 307 | 0.09 | 0.61 |
| Diablo Canyon settlement-related disallowance (8) | - | - | - | - | 32 | - | 0.06 | - |
| GT&S revenue timing impact (9) | - | (193) | - | (0.38) | (88) | (193) | (0.17) | (0.38) |
| Net benefit from derivative litigation settlement (10) | - | - | - | - | (38) | - | (0.07) | - |
| GT&S capital disallowance | - | 17 | - | 0.04 | - | 130 | - | 0.26 |
| **PG&E Corporation's Earnings from Operations (11)** | **$ 327** | **$ 675** | **$ 0.63** | **$ 1.33** | **$ 1,889** | **$ 1,884** | **$ 3.68** | **$ 3.76** |

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except as indicated below.

[1] "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods.



[2] PG&E Corporation, on a consolidated basis, incurred a one-time charge of $147 million during the three and twelve months ended December 31, 2017, as a result of the Tax Cuts and Jobs Act, which was signed into law on December 22, 2017. The Utility's charge of $64 million was related to deferred taxes not reflected in the authorized revenue requirements, such as deferred tax assets associated with disallowed plant, and PG&E Corporation's charge of $83 million was primarily related to net operating loss carryforwards and compensation-related deferred tax assets.

[3] The Utility incurred costs of $82 million (before the tax impact of $33 million) during the three and twelve months ended December 31, 2017, associated with the Northern California wildfires. This includes charges of $64 million (before the tax impact of $26 million) for the three and twelve months ended December 31, 2017, for the reinstatement of liability insurance coverage and $18 million (before the tax impact of $7 million) during the three and twelve months ended December 31, 2017, for legal and other expenses.

[4] The Utility incurred costs, net of insurance, of $15 million (before the tax impact of $6 million) and $60 million (before the tax impact of $24 million) during the three and twelve months ended December 31, 2017, respectively, associated with the Butte fire. This includes accrued charges of $350 million (before the tax impact of $143 million) during the twelve months ended December 31, 2017, related to estimated third-party claims. The Utility also incurred charges of $15 million (before the tax impact of $6 million) and $60 million (before the tax impact of $25 million) during the three and twelve months ended December 31, 2017, respectively, for legal costs. These costs were partially offset by $350 million (before the tax impact of $143 million) recorded during the twelve months ended December 31, 2017, for expected insurance recoveries.

[5] The Utility incurred costs of $12 million (before the tax impact of $5 million) and $89 million (before the tax impact of $37 million) during the three and twelve months ended December 31, 2017, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

[6] The Utility incurred costs of $2 million (before the tax impact of $1 million) and $10 million (before the tax impact of $4 million) during the three and twelve months ended December 31, 2017, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

[7] The Utility incurred costs of $71 million (before the tax impact of $24 million) during the twelve months ended December 31, 2017, for fines and penalties. This includes costs of $32 million (before the tax impact of $13 million) during the twelve months ended December 31, 2017, associated with safety-related cost disallowances imposed by the CPUC in its April 9, 2015 San Bruno Penalty Decision in the gas transmission pipeline investigations. The Utility also recorded $15 million (before the tax impact of $6 million) during the twelve months ended December 31, 2017, for penalty imposed by the CPUC in its final phase two decision of the 2015 GT&S rate case for prohibited ex parte communications. In addition, the Utility recorded $24 million (before the tax impact of $5 million) during the twelve months ended December 31, 2017, in connection with the PD in the OII into Compliance with Ex Parte Communication Rules.

[8] Consistent with the CPUC decision adopted on January 11, 2018 in connection with the retirement of the Diablo Canyon Power Plant, the Utility recorded a disallowance of $47 million (before the tax impact of $15 million) during the twelve months ended December 31, 2017, comprised of cancelled projects of $24 million (before the tax impact of $6 million) and disallowed license renewal costs of $23 million (before the tax impact of $9 million).

[9] As a result of the CPUC's final phase two decision in the 2015 GT&S rate case, during the twelve months ended December 31, 2017, the Utility recorded revenues of $150 million (before the tax impact of $62 million) in excess of the 2017 authorized revenue requirement, which includes the final component of under-collected revenues retroactive to January 1, 2015.

[10] PG&E Corporation recorded proceeds from insurance, net of plaintiff payments, of $65 million (before the tax impact of $27 million) during the twelve months ended December 31, 2017, associated with the settlement agreement in connection with the shareholder derivative litigation that was approved by the court on July 18, 2017. This includes $90 million (before the tax impact of $37 million) for insurance recoveries partially offset by $25 million (before the tax impact of $10 million) for plaintiff legal fees paid in connection with the settlement during the twelve months ended December 31, 2017.

[11] "Earnings from operations" is a non-GAAP financial measure.

**Reconciliation of Key Drivers of PG&E Corporation's EPS from Operations (Non-GAAP):**

| | Three Months Ended December 31, | | Twelve Months Ended December 31, | |
|---|---|---|---|---|
| (in millions, except per share amounts) | Earnings | Earnings per Common Share (Diluted) | Earnings | Earnings per Common Share (Diluted) |
| 2016 Earnings from Operations [1] | $ 675 | $ 1.33 | $ 1,884 | $ 3.76 |
| Timing of 2015 GT&S revenue impact [2] | (172) | (0.33) | - | - |
| Timing of taxes [3] | (90) | (0.18) | - | - |
| Impact of 2017 GRC decision [4] | (47) | (0.09) | (139) | (0.27) |
| Timing of operational spend [5] | (31) | (0.06) | - | - |
| CEE Incentive Award [6] | (10) | (0.02) | (10) | (0.02) |
| Increase in shares outstanding | - | (0.02) | - | (0.08) |
| Tax benefit on stock compensation [7] | - | - | 31 | 0.06 |
| Miscellaneous | (23) | (0.05) | 20 | 0.03 |
| Growth in rate base earnings [8] | 25 | 0.05 | 103 | 0.20 |
| **2017 Earnings from Operations [1]** | **$ 327** | **$ 0.63** | **$ 1,889** | **$ 3.68** |

[1] See first table above for a reconciliation of EPS on a GAAP basis to EPS from Operations. All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except for tax benefits on stock compensation. See Footnote 3 below.

[2] Represents the impact in 2016 of the delay in the Utility's 2015 GT&S rate case. The CPUC issued its final phase two decision on December 1, 2016, delaying recognition of the full 2016 revenue increase until the fourth quarter of 2016.

[3] Represents the timing of taxes reportable in quarterly statements in accordance with ASC 740 and results from variances in the percentage of quarterly earnings to annual earnings.

[4] Represents the impact of lower tax repair benefits as a result of the CPUC's final decision in the 2017 GRC proceeding.

[5] Represents timing of operational expense spending during the three months ended December 31, 2017 as compared to the same period in 2016.

[6] Represents the Customer Energy Efficiency ("CEE") incentive award received during the fourth quarter of 2016, with no similar amount in 2017. The 2017 award of $21.9 million was fully offset by the reduction approved by the CPUC related to the rehearing of the 2006 - 2008 CEE incentive awards.

[7] Represents the excess tax benefit related to share-based compensation awards that vested during the twelve months ended December 31, 2017. Pursuant to ASU 2016-09, *Compensation - Stock Compensation (Topic 718)*, which PG&E Corporation and the Utility adopted in 2016, excess tax benefits associated with vested awards are reflected in net income.

[8] Represents the impact of the increase in rate base authorized in various rate cases, including the 2017 GRC, during the three and twelve months ended December 31, 2017 as compared to the same periods in 2016.



**Key Factors Affecting Financial Results**

PG&E Corporation and the Utility believe that their financial condition, results of operations, liquidity, and cash flows may be materially affected by the following factors:

- *The Impact of the Northern California Wildfires.* PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. The Utility incurred costs of $219 million for service restoration and repairs to the Utility's facilities (including an estimated $97 million in capital expenditures) in connection with these fires. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs through CEMA. If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damages, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial. In addition to such claims, as well as

claims under other theories of liability, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material effect on PG&E Corporation and the Utility. Further, the Utility also could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations. If the Utility were to determine that it is both probable that a loss has occurred and the amount of loss can be reasonably estimated, a liability would be recorded consistent with the principles discussed in Note 13 to Notes to the Consolidated Financial Statements in Item 8. To the extent not offset by insurance recoveries, the liability would affect the balance sheet equity of PG&E Corporation and the Utility. (See "Enforcement and Litigation Matters" in Note 13 to Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.)

- *The Applicability of the Doctrine of Inverse Condemnation in PG&E Corporation and the Utility's Wildfire Litigation.* The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation and the Utility are subject, could significantly expand the potential shareholder liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. Although the imposition of liability is premised on the assumption that utilities have the ability to recover these costs from their customers, there can be no guarantee that the CPUC would authorize cost recovery even if a court decision imposes liability under the doctrine of inverse condemnation. In December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC's prudent manager standard. That determination is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison. (See "Enforcement and Litigation Matters" in Note 13 to Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.)
- *The Tax Cut and Jobs Act.* On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and eliminates bonus depreciation for utilities. As a result of the Tax Act, beginning in 2018, PG&E Corporation and the Utility anticipate a reduction in revenues, lower effective income tax rates and lower income tax expense. In addition, the Utility expects a rate base increase primarily due to the elimination of bonus depreciation. (See "The Tax Cuts and Job Act of 2017" and "Regulatory Matters" in this Item 7. MD&A and Note 3 and Note 8 in the Notes to the Consolidated Financial Statements.)
- *The Outcome of Enforcement, Litigation, and Regulatory Matters.* The Utility's financial results may continue to be impacted by the outcome of current and future enforcement, litigation, and regulatory matters, including the impact of the Northern California wildfires, the Butte fire, the safety culture OII and any related fines, penalties, or other ratemaking tools that could be imposed by the CPUC, including as a result of the phase two of the proceeding, the ex parte OII and the related proposed decision, the potential recommendations that the third-party monitor (retained by the Utility in the first quarter of 2017 as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction) may make, and potential penalties in connection with the Utility's safety and other self-reports. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8, Item 3. Legal Proceedings, and Item 1A. Risk Factors.)
- *The Timing and Outcome of Ratemaking Proceedings.* The Utility's financial results may be impacted by the timing and outcome of its 2019 GT&S rate case, and FERC TO18 and TO19 rate cases, as well as the recent remand decision by the Ninth Circuit regarding an ROE adder for transmission facilities. (See "Regulatory Matters - 2019 Gas Transmission and Storage Rate Case" and "Regulatory Matters − FERC Transmission Owner Rate Cases" below for more information.) The outcome of regulatory proceedings can be affected by many factors, including intervening parties' testimonies, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.
- *The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures.* In any given year the Utility's ability to earn its authorized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 2018 it will incur unrecovered pipeline-related expenses ranging from $35 million to $60 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the CPUC decision in the Utility's 2015 GT&S rate case established various cost caps that will increase the risk of overspend over the rate case cycle through 2018. (See "Disallowance of Plant Costs" in Note 13 of the Notes to the

Consolidated Financial Statements in Item 8.)



- *The Amount and Timing of the Utility's Financing Needs.* PG&E Corporation's and the Utility's ability to access the capital markets, ability to borrow under its loan financing arrangements and the terms and rates of future financings could be materially affected by the outcome of, or market perception of, the matters discussed in Note 13 of the Notes to the Consolidated Financial Statements, including liabilities, if any, incurred in relation to the Northern California wildfires, adverse effects on PG&E Corporation's and the Utility's ability to comply with consolidated debt to total capitalization ratio covenants in their financing arrangements and regulatory capital structure requirements resulting therefrom, adverse changes in their respective credit ratings, general economic and market conditions, and other factors. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In 2017, PG&E Corporation issued $416 million of common stock and made equity contributions of $455 million to the Utility. PG&E Corporation forecasts that it will need to continue to issue a material amount of equity in future years, primarily to support the Utility's capital expenditures. PG&E Corporation may seek to issue additional equity to fund unrecoverable pipeline-related expenses and to pay claims, losses, fines, and penalties that may be required by the outcome of litigation and enforcement matters. Additional issuances of equity, if any, could have a material dilutive impact on PG&E Corporation's EPS.
- *Changes in the Utility Industry.* The Utility is committed to delivering safe, reliable, sustainable, and affordable electric and gas services to its customers. Increasing demands from state laws and policies relating to increased renewable energy resources, the reduction of GHG emissions, the expansion of energy efficiency programs, the development and widespread deployment of distributed generation and self-generation resources, and the development of energy storage technologies have increased pressure on the Utility to achieve efficiencies in its operations while continuing to provide customers with safe, reliable, and affordable service. The utility industry is also undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. California's environmental policy objectives are accelerating the pace and scope of the industry change. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policy makers notwithstanding a recent change in the federal approach to such matters. In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, EV infrastructure and state infrastructure modernization (e.g. rail and water projects). The Utility forecasts over $1 billion in grid investments through 2020, which would include increased remote control and sensor technology of the grid, integration investments in connection with DER bi-directional energy flows and voltage fluctuations, advanced grid data analytics, grid storage that enables renewable integration, expanded infrastructure for light, medium, and heavy-duty EVs, transmission integration for renewables, and energy efficiency and demand response programs. In addition, these changes brought about by technological advancements and climate policy may cause a reduction in natural gas usage and increase natural gas costs. The combination of reduced natural gas load and increased costs could result in higher natural gas customer bills and potential cost recovery risk.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this 2017 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this 2017 Form 10-K. See the section entitled "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2017, 2016, and 2015. See "Key Factors Affecting Financial Results" above for further discussion about factors that could affect future results of operations.

### PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income available for common shareholders:

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Consolidated Total | $ 1,646 | $ 1,393 | $ 874 |
| PG&E Corporation | (31) | 5 | 26 |
| Utility | $ 1,677 | $ 1,388 | $ 848 |

PG&E Corporation's net income consists primarily of income taxes, interest expense on long-term debt, and other income from investments. The decrease in PG&E Corporation's net income for 2017, as compared to 2016, is primarily due to the impact of the Tax Act and interest expense, partially offset by the impact of the San Bruno Derivative Litigation. Results include approximately $30 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in 2015, with no corresponding gains in 2016 or 2017.

### Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2017, 2016, and 2015. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

| (in millions) | 2017 That Impacted Earnings | 2017 That Did Not Impact Earnings | 2017 Total Utility | 2016 That Impacted Earnings | 2016 That Did Not Impact Earnings | 2016 Total Utility | 2015 That Impacted Earnings | 2015 That Did Not Impact Earnings | 2015 Total Utility |
|---|---|---|---|---|---|---|---|---|---|
| | Revenues and Costs: | | | Revenues and Costs: | | | Revenues and Costs: | | |
| Electric operating revenues | $ 7,897 | $ 5,230 | $ 13,127 | $ 7,955 | $ 5,910 | $ 13,865 | $ 7,442 | $ 6,215 | $ 13,657 |
| Natural gas operating revenues | 2,969 | 1,042 | 4,011 | 2,767 | 1,035 | 3,802 | 2,082 | 1,094 | 3,176 |
| **Total operating revenues** | **10,866** | **6,272** | **17,138** | **10,722** | **6,945** | **17,667** | **9,524** | **7,309** | **16,833** |
| Cost of electricity | - | 4,309 | 4,309 | - | 4,765 | 4,765 | - | 5,099 | 5,099 |
| Cost of natural gas | - | 746 | 746 | - | 615 | 615 | - | 663 | 663 |
| Operating and maintenance | 5,112 | 1,217 | 6,329 | 5,787 | 1,565 | 7,352 | 5,402 | 1,547 | 6,949 |
| Depreciation, amortization, and decommissioning | 2,854 | - | 2,854 | 2,754 | - | 2,754 | 2,611 | - | 2,611 |
| **Total operating expenses** | **7,966** | **6,272** | **14,238** | **8,541** | **6,945** | **15,486** | **8,013** | **7,309** | **15,322** |
| **Operating income** | **2,900** | **-** | **2,900** | **2,181** | **-** | **2,181** | **1,511** | **-** | **1,511** |
| Interest income [(1)] | | | 30 | | | 22 | | | 8 |
| Interest expense [(1)] | | | (877) | | | (819) | | | (763) |
| Other income, net [(1)] | | | 65 | | | 88 | | | 87 |
| **Income before income taxes** | | | 2,118 | | | 1,472 | | | 843 |
| Income tax provision (benefit) [(1)] | | | 427 | | | 70 | | | (19) |
| **Net income** | | | 1,691 | | | 1,402 | | | 862 |
| Preferred stock dividend requirement [(1)] | | | 14 | | | 14 | | | 14 |
| **Income Available for Common Stock** | | | **$ 1,677** | | | **$ 1,388** | | | **$ 848** |

[(1)] These items impacted earnings.

**Utility Revenues and Costs that Impacted Earnings**

The following discussion presents the Utility's operating results for 2017, 2016, and 2015, focusing on revenues and expenses that impacted earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased $144 million, or 1% in 2017 compared to 2016, primarily due to higher electric transmission revenues.

The Utility's electric and natural gas operating revenues that impacted earnings increased $1.2 billion or 13% in 2016 compared to 2015, primarily as a result of approximately $700 million of incremental revenues authorized in the 2015 GT&S rate case and approximately $425 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO17 rate case.

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings decreased $675 million, or 12%, in 2017 compared to 2016. In 2017, the Utility incurred $455 million less in disallowed charges (the Utility recorded a $47 million disallowance related to the Diablo Canyon settlement in 2017 as compared to $502 million of disallowed capital charges related to the San Bruno Penalty Decision and 2015 GT&S rate case decision in 2016) and $447 million less in charges related to the Butte fire (the Utility recorded $410 million in charges in 2017 as compared to $857 million in 2016). These decreases were partially offset by insurance recoveries related to the Butte fire decreasing by approximately $275 million (the Utility recorded $350 million in insurance recoveries in 2017 as compared to approximately $625 million in 2016). (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility's operating and maintenance expenses that impacted earnings increased $385 million, or 7%, in 2016 compared to 2015, primarily due to $857 million in charges for third-party claims, Utility clean-up, repair, and legal costs related to the Butte fire, $219 million in permanently disallowed capital spending, $34 million in charges recorded in connection with the final CPUC decision related to the natural gas distribution facilities record-keeping investigation, the federal criminal trial, and the atmospheric corrosion inspection self-report, $24 million in higher pipeline-related expenses and legal and regulatory related expenses during 2016, an escalation related to labor, benefits, and service contracts, and accelerated transmission and distribution project work. These increases were partially offset by $500 million in charges associated with the San Bruno Penalty Decision for customer refunds and fines incurred in 2015 with no corresponding charges in 2016 and approximately $125 million in lower disallowed capital charges associated with the San Bruno Penalty Decision in 2016. Additionally, the Utility recorded approximately $576 million more in insurance recoveries (in 2016, the Utility recorded $625 million in insurance recoveries related to the Butte fire as compared to $49 million of insurance recoveries for third-party claims related to the San Bruno accident in 2015).

The Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires and any additional charges associated with costs related to the Butte fire. (See Item 1A. Risk Factors above and Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased $100 million, or 4% in 2017 compared to 2016 and $143 million, or 5% in 2016 compared to 2015. In 2017, the increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by the CPUC in the 2017 GRC. In 2016, the increase was primarily due to the impact of capital additions.

*Interest Expense*

The Utility's interest expenses increased by $58 million, or 7% in 2017 compared to 2016, primarily due to the issuance of additional long-term debt. The Utility's interest expenses increased by $56 million, or 7% in 2016 compared to 2015, primarily due to the issuance of additional long-term debt.

*Interest Income and Other Income, Net*

There were no material changes to interest income and other income, net for the periods presented.

*Income Tax Provision*

The Utility's income tax provision increased $357 million in 2017 compared to 2016. The increase in the tax provision was primarily the result of the statutory tax effect of higher pre-tax income in 2017 compared to 2016 and an adjustment required to record the change in deferred tax balances due to tax reform in 2017 with no comparable adjustment in 2016. (For more information see "Tax Reform" below and Note 8 of the Consolidated Financial Statements.)

The Utility's income tax provision increased $89 million in 2016 compared to 2015. The increase in the tax provision was primarily the result of the statutory tax effect of higher pre-tax income in 2016 compared to 2015, partially offset by higher tax benefits from property-related timing differences in 2016 compared to 2015. The higher effective tax rate was driven by higher pre-tax earnings in 2016, partially offset by rate impact from property-related timing differences.

The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Federal statutory income tax rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) [(1)] | 1.6 | (2.2) | (4.8) |
| Effect of regulatory treatment of fixed asset differences [(2)] | (16.8) | (23.4) | (33.7) |
| Tax credits | (1.1) | (0.8) | (1.3) |
| Benefit of loss carryback | - | (1.1) | (1.5) |
| Non-deductible penalties [(3)] | 0.4 | 0.8 | 4.3 |
| Tax Reform Adjustment [(4)] | 3.0 | - | - |
| Other, net [(5)] | (2.0) | (3.5) | (0.2) |
| **Effective tax rate** | **20.1%** | **4.8%** | **(2.2)%** |

(1) Includes the effect of state flow-through ratemaking treatment. In 2016 and 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions. The 2017 amount reflects an agreement with the IRS on a 2013 audit related to generation repairs deductions.

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted 2016 and 2017. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.

(3) Primarily represents the effects of a non-tax deductible penalty associated with the Butte fire for 2017, non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for 2016 and the effects of the San Bruno Penalty Decision for 2015.

(4) Represents the required adjustment to deferred tax balances, due to the federal income tax rate being lowered from 35% to 21% beginning in 2018 as a result of the enactment of the Tax Act.

(5) These amounts primarily represent the impact of tax audit settlements.

**Utility Revenues and Costs that did not Impact Earnings**

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs (see below for more detail).

*Cost of Electricity*

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

| **(in millions)** | **2017** | **2016** | **2015** |
|---|---|---|---|
| Cost of purchased power | $ 4,039 | $ 4,510 | $ 4,805 |
| Fuel used in own generation facilities | 270 | 255 | 294 |
| **Total cost of electricity** | **$ 4,309** | **$ 4,765** | **$ 5,099** |
| Average cost of purchased power per kWh [(1)] | $ 0.140 | $ 0.109 | $ 0.100 |
| **Total purchased power (in millions of kWh) [(2)]** | **28,750** | **41,324** | **48,175** |

(1) Average cost of purchased power was impacted primarily by lower Utility electric customer demand due to their departure to CCAs or direct access providers and a larger percentage of higher cost renewable energy resources being allocated to fewer remaining Utility electric customers. See further discussion in Item 7. MD&A, "Legislative and Regulatory Initiatives - Power Charge Indifference Adjustment OIR", below.

(2) The decrease in purchased power for 2017 compared to 2016 was primarily due to lower Utility electric customer demand and an increase in generation from hydroelectric facilities.

*Cost of Natural Gas*

The Utility's cost of natural gas includes the costs of procurement, storage and transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

| **(in millions)** | **2017** | **2016** | **2015** |
|---|---|---|---|
| Cost of natural gas sold | $ 627 | $ 481 | $ 518 |
| Transportation cost of natural gas sold | 119 | 134 | 145 |
| **Total cost of natural gas** | **$ 746** | **$ 615** | **$ 663** |
| Average cost per Mcf [(1)] of natural gas sold | $ 2.97 | $ 2.45 | $ 2.74 |
| **Total natural gas sold (in millions of Mcf) [(2)]** | **211** | **196** | **189** |

(1) One thousand cubic feet

(2) The increase in natural gas sold for 2017 compared to 2016 was primarily due to cooler temperatures and resulted in additional customer heating demand.

*Operating and Maintenance Expenses*

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2017, 2016, and 2015, no material amounts were incurred above authorized amounts.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See Item 1A. Risk Factors and Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its cost of capital. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. (See "Regulatory Matters" in Item 7. MD&A.) The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and declare and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, and issuances and repayments under its revolving credit facility and commercial paper program. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters, including the outcome of the uncertainties and potential liabilities associated with the Northern California wildfires. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. In December 2017, following PG&E Corporation's announcement that it was suspending its dividend due to the uncertainty related to the causes and potential liabilities associated with the Northern California wildfires, all of the ratings of PG&E Corporation and the Utility were placed under review for downgrade by Moody's Investor Services. Additionally, in December 2017, Standard & Poor's Global Ratings lowered the Utility's preferred stock credit rating and placed all of the ratings of PG&E Corporation and the Utility on CreditWatch with negative implications. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability positions. (See Notes 9 and 13 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation's and the Utility's equity needs could increase materially and its liquidity and cash flows could be materially affected by potential costs and other liabilities in connection with the Northern California wildfires. The Utility's equity needs will also continue to be affected by the timing and amount of disallowed capital expenditures, and by fines, penalties and claims that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. In addition, PG&E Corporation's and the Utility's ability to access the capital markets in a manner consistent with its past practices, if at all, could be adversely affected by such matters. (See Item 1A. Risk Factors.)

As a result of the Tax Act, the Utility anticipates an annual reduction to revenue requirements of approximately $500 million starting in 2018. In addition to this reduction in future revenue requirements, the Tax Act's other provisions, in particular the elimination of bonus depreciation, are expected to accelerate when PG&E Corporation resumes paying federal taxes; although future taxes will be lower due to the lower federal tax rate. PG&E Corporation now expects to pay federal taxes starting in 2020, although that timing would be impacted by any significant changes to future results of operations. Additionally, because the revenue reduction is expected to precede the reduction in federal income tax payments, PG&E Corporation's and the Utility's operating cash flows will be negatively impacted resulting in additional financing needs.

**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds.

**Financial Resources**

***Debt Financings***

In February 2017, the Utility's $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid. Additionally, in February 2017, the Utility entered into a $250 million floating rate unsecured term loan maturing on February 22, 2018.

In March 2017, the Utility issued $400 million principal amount of 3.30% senior notes due March 15, 2027 and $200 million principal amount of 4.00% senior notes due December 1, 2046. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

In November 2017, the Utility issued $1,150 million principal amount of 3.30% senior notes due December 1, 2027 and $850 million principal amount of 3.95% senior notes due December 1, 2047. The proceeds were used to repay all of the $700 million outstanding principal amount of its 5.63% senior notes due November 30, 2017, all of the $250 million floating rate unsecured term loan maturing February 22, 2018 and $400 million of the 8.25% senior notes due October 15, 2018, and the balance, for general corporate purposes.

In November 2017, the Utility issued $500 million of floating rate senior notes due November 28, 2018. The proceeds were used towards repayment of the $250 million unsecured floating rate notes due November 30, 2017 and the balance was used to support the Northern California wildfire response efforts.

On January 9, 2018, the Utility sent a notice of redemption to redeem all $400 million aggregate principal amount of the 8.25% senior notes due October 15, 2018 on February 18, 2018. On January 31, 2018, the Utility deposited with the trustee funds sufficient to effect the early redemption of these bonds and satisfy and discharge its remaining obligation of $400 million.

***Equity Financings***

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate gross price of up to $275 million. During the twelve months ended December 31, 2017, PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $28.4 million, net of commissions paid of $0.2 million. There were no issuances under the February 2017 EDA for the three months ended December 31, 2017. As of December 31, 2017, the remaining gross sales available under this agreement were $246.3 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During 2017, 7.4 million shares were issued for cash proceeds of $366.4 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility. For the year ended December 31, 2017, PG&E Corporation made equity contributions to the Utility of $455 million.

***Pollution Control Bonds***

In June 2017, the Utility repurchased and retired $345 million principal amount of pollution control bonds Series 2004 A through D. Additionally, in June 2017, the Utility remarketed three series of pollution control bonds, previously held in treasury, totaling $145 million in principal amount. Series 2008 F and 2010 E bear interest at 1.75% per annum. Although the stated maturity date for Series 2008 F and 2010 E is November 1, 2026, these bonds have a mandatory redemption date of May 30, 2022. Series 2008 G bears interest at 1.05% per annum and matures on December 1, 2018.

***Revolving Credit Facilities and Commercial Paper Programs***

In May 2017, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022. At December 31, 2017, PG&E Corporation and the Utility had $168 million and $2.9 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. For the year ended December 31, 2017, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $81 million and $469 million, and a maximum outstanding balance of $161 million and $1.1 billion, respectively. At December 31, 2017, PG&E Corporation and the Utility had outstanding commercial paper balances of $132 million and $50 million, respectively. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At December 31, 2017, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 50% and 49%, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation owns, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At December 31, 2017, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

**Dividends**

The Board of Directors of PG&E Corporation and the Utility each has the authority to declare dividends on PG&E Corporation's common stock and the Utility's common and preferred stock, respectively. Dividends are not payable unless and until declared by the applicable Board of Directors. Each Board of Directors retains authority to change the respective common or preferred stock dividend policy and dividend payout ratio or rate at any time, especially if unexpected events occur that would change their view as to the prudent level of cash conservation.

***PG&E Corporation***

For the first quarter of 2017, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share. In May 2017, the Board of Directors of PG&E Corporation approved a new annual common stock dividend of $2.12 per share. As a result, for the second and third quarters of 2017, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.53 per share. In 2017, total dividends declared were $1.55 per share. For the first quarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. For each of the second, third and fourth quarters of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share. In 2016, total dividends declared were $1.925 per share. For each of the quarters in 2015, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share, for annual dividends of $1.82 per share. Dividends paid to common shareholders by PG&E Corporation were $1.0 billion in 2017, $921 million in 2016, and $856 million in 2015.

***Utility***

For the first quarter of 2017, the Board of Directors of the Utility declared a common stock dividend of $244 million to PG&E Corporation. For the second and third quarter of 2017, the Board of Directors of the Utility declared common stock dividends of $270 million to PG&E Corporation. In 2017, total dividends paid by the Utility to PG&E Corporation were $784 million. For the first quarter of 2016, the Board of Directors of the Utility declared a common stock dividend of $179 million to PG&E Corporation. For each of the second, third and fourth quarters of 2016, the Board of Directors of the Utility declared common stock dividends of $244 million to PG&E Corporation. In 2016, total dividends paid by the Utility to PG&E Corporation were $911 million. For each of the quarters in 2015, the Board of Directors of the Utility declared common stock dividends of $179 million to PG&E Corporation for annual dividends paid of $716 million. In addition, the Utility paid $14 million of dividends on preferred stock in each of 2017, 2016, and 2015. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends.

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** |
| Net cash provided by operating activities | $ 5,916 | $ 4,344 | $ 3,747 |
| Net cash used in investing activities | (5,650) | (5,526) | (5,211) |
| Net cash provided by financing activities | 110 | 1,194 | 1,468 |
| **Net change in cash and cash equivalents** | **$ 376** | **$ 12** | **$ 4** |

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During 2017, net cash provided by operating activities increased by $1.6 billion compared to 2016. This increase was primarily due to additional electric and natural gas operating revenues collected as authorized by the CPUC in the 2015 GT&S rate case, the $400 million refund to natural gas customers in the second quarter of 2016, as required by the San Bruno Penalty Decision (with no corresponding activity in 2017), and the receipt of approximately $300 million of insurance recoveries related to the Butte fire in 2017 as compared to $50 million of insurance recoveries related to the Butte fire during 2016.

During 2016, net cash provided by operating activities increased by $597 million compared to 2015. This increase was partially due to the Utility receiving an additional $170 million in tax refunds in 2016 as compared to 2015. The remaining increase was primarily due to fluctuations in activities within the normal course of business such as timing and amount of customer billings and vendor billings and payments.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and amount of costs in connection with the Northern California wildfires, as well as potential liabilities in connection with third-party claims and fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;
- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with the current and future enforcement, litigation, and regulatory matters, including the impact of the Butte fire and the timing and amount of related insurance recoveries, the safety culture OII, including other ratemaking tools that could be imposed by the CPUC as a result of the phase two of the proceeding, the ex parte OII and the related proposed decision, costs associated with potential recommendations that the third-party monitor may make related to the Utility's conviction in the federal criminal trial, and potential penalties in connection with the Utility's safety and other self-reports;
- the Tax Act, which is expected to accelerate the timing of federal tax payments and reduce revenue requirements, resulting in lower operating cash flows;
- the timing and outcomes of the 2019 GT&S, TO18, and TO19 rate cases and other ratemaking and regulatory proceedings;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its electric and natural gas systems; and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

***Investing Activities***

Net cash used in investing activities increased by $124 million during 2017 as compared to 2016 primarily due to an increase in capital expenditures. Net cash used in investing activities increased by $315 million during 2016 as compared to 2015 primarily due to an increase of approximately $440 million in capital expenditures, partially offset by an increase in restricted cash released from escrow by approximately $160 million.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $6.3 billion in capital expenditures in 2018 and $6.0 billion in 2019.

***Financing Activities***

During 2017, net cash provided by financing activities decreased by $1.1 billion as compared to 2016. This decrease was primarily due to net commercial repayments of $972 million in 2017 as compared to net repayments of $9 million in 2016. During 2016, net cash provided by financing activities decreased by $274 million as compared to 2015. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

## CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2017:

| | Payment due by period | | | | |
|---|---|---|---|---|---|
| (in millions) | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years | Total |
| **Utility** | | | | | |
| Long-term debt [1]: | $ 1,253 | $ 3,117 | $ 2,523 | $ 25,114 | $ 32,007 |
| Purchase obligations [2]: | | | | | |
| Power purchase agreements: | 3,148 | 6,169 | 5,539 | 27,188 | 42,044 |
| Natural gas supply, transportation, and storage | 388 | 315 | 186 | 357 | 1,246 |
| Nuclear fuel agreements | 96 | 245 | 130 | 151 | 622 |
| Pension and other benefits [3] | 351 | 701 | 701 | 351 | 2,104 |
| Operating leases [2] | 44 | 81 | 63 | 138 | 326 |
| Preferred dividends [4] | 14 | 28 | 28 | - | 70 |
| **PG&E Corporation** | | | | | |
| Long-term debt [1]: | 8 | 354 | - | - | 362 |
| **Total Contractual Commitments** | **$ 5,302** | **$ 11,010** | **$ 9,170** | **$ 53,299** | **$ 78,781** |

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2017 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

(2) See "Purchase Commitments" and "Other Commitments" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

(3) See Note 11 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.

(4) Beginning with the three-month period ending January 31, 2018, quarterly cash dividends on the Utility's preferred stock were suspended. While the timing of cumulative dividend payments is uncertain, it is assumed for the table above to be payable within a fixed period of five years based on historical performance. (See Note 6 of the Consolidated Financial Statements in Item 8.)

The contractual commitments table above excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 8 of the Notes to the Consolidated Financial Statements in Item 8.

### Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) in Item 8.

## ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and Legal Proceedings in Item 3. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

**REGULATORY MATTERS**

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC, and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

The Utility is still analyzing the impact of the Tax Act on revenue requirements and rate base for the 2017 GRC, the 2015 GT&S Rate Case, the recently submitted 2019 GT&S Rate Case, and the pending TO19 rate case. However, on an aggregate basis, the Utility currently anticipates an annual reduction to revenue requirements of approximately $500 million starting in 2018, and incremental increases to rate base of approximately $500 million in 2018 and $800 million in 2019, as a result of the Tax Act.

As a result of the Tax Act, the Utility intends to file by the end of March 2018 (i) revised revenue requirements and rate base in its 2017 GRC (for years 2018 and 2019) and 2015 GT&S rate case (for 2018) as well as a proposed implementation plan in connection thereto, and (ii) revised revenue requirement and rate base forecast in its 2019 GT&S rate case. The Utility is unable to predict the timing and outcome of the CPUC decision in connection with such filings. As discussed below, the 2017 GRC final decision established a tax memorandum account to track revenue differences resulting from tax law changes, among other items, for disposition in the 2020 GRC. The March filings will accelerate that timing. (See "Tax Cuts and Jobs Act of 2017" in Item 7. MD&A and Note 3 and Note 8 in the Notes to the Consolidated Financial Statements.)

***2017 General Rate Case***

On May 11, 2017, the CPUC issued a final decision in the Utility's 2017 GRC, which determined the annual amount of base revenues (or "revenue requirements") that the Utility is authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The final decision approved, with certain modifications, the settlement agreement that the Utility, the ORA, TURN, and 12 other intervening parties jointly submitted to the CPUC on August 3, 2016 (the "settlement agreement"). Modifications from the settlement agreement to the final decision included a tax memorandum account and approval of a stand-alone application with the CPUC or a filing in the CPUC's ongoing residential rate reform proceeding to recover customer outreach and other costs incurred as a result of residential rate reform implementation. The new tax memorandum account will track any revenue differences resulting from changes in income tax expense caused by net revenue changes, mandatory or elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes during the 2017 through 2019 GRC period. The account will remain open and the balance in the account will be reviewed in every subsequent GRC proceeding until a CPUC decision closes the account.

The final decision approved a revenue requirement increase of $88 million for 2017, with additional increases of $444 million in 2018 and $361 million in 2019, in line with the amounts proposed in the settlement agreement. The following table shows the revenue requirement amounts approved in the final decision based on line of business and cost category as well as the differences between the 2016 authorized revenue requirements and the amounts approved in the final decision:

| (in millions)<br>**Line of Business:** | | **Amounts Approved in Final Decision** [(1)] | | **Increase/ (Decrease) 2016 vs. Final Decision** |
|---|---|---|---|---|
| Electric distribution | $ | 4,151 | $ | (62) |
| Gas distribution | | 1,738 | | (3) |
| Electric generation | | 2,115 | | 153 |
| **Total revenue requirements** | **$** | **8,004** | **$** | **88** |

| (in millions)<br>**Cost Category:** | | | | |
|---|---|---|---|---|
| Operations and maintenance | $ | 1,794 | $ | 131 |
| Customer services | | 334 | | 15 |
| Administrative and general | | 912 | | (99) |
| Less: Revenue credits | | (152) | | (21) |
| Franchise fees, taxes other than income, and other adjustments | | 170 | | 132 |
| Depreciation (including costs of asset removal), return, and income taxes | | 4,946 | | (70) |
| **Total revenue requirements** | **$** | **8,004** | **$** | **88** |

(1) Amounts approved in the final decision are the same as the amounts that were proposed in the settlement agreement.

As required by the final decision, the Utility has submitted a variety of compliance filings, including filings on June 12, 2017, which provides accounting for the January 2017 $300 million expense reduction announcement and on July 10, 2017, providing an update of the cost effectiveness study for the SmartMeter™ Upgrade project. On February 8, 2018, the CPUC extended the statutory deadline for the 2017 GRC from February 8, 2018 to August 9, 2018, in order to allow for comments and CPUC action on any PD on the SmartMeter™ Upgrade cost effectiveness study, as well as one other remaining GRC compliance item.

***2020 General Rate Case***

The Utility expects to file the 2020 GRC by September 1, 2018. On November 30, 2017, the Utility filed its first RAMP submittal to the CPUC in advance of its 2020 GRC filing. The RAMP is a new CPUC requirement directing each large energy utility to submit a report describing how it assesses its risks and how it plans to mitigate and minimize such risks in advance of the utility's GRC application. The objective of this filing is to inform the CPUC of the Utility's top safety-related risks, risk assessment procedures, and proposed mitigations of those risks for 2020-2022.

The SED is expected to submit a report on the Utility's RAMP submittal and hold a workshop on the report, after which parties will have the opportunity to file comments. The RAMP results will be incorporated in the Utility's 2020 GRC.

***2015 Gas Transmission and Storage Rate Case***

During 2016, the CPUC issued final decisions in phase one and phase two of the Utility's 2015 GT&S rate case. The phase one decision adopted the revenue requirements that the Utility is authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period (2015 through 2018). The phase two decision determined the allocation of the $850 million penalty assessed in the San Bruno Penalty Decision and the revenue requirement reduction for the five-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding.

The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. A draft of the audit report is expected in the first quarter of 2018. The decision established new one-way balancing accounts to track costs as well as various cost caps that will increase the risk of disallowance over the current rate case cycle. The Utility would be required to take a charge in the future if the CPUC's audit of 2011 through 2014 capital spending resulted in additional permanent disallowance.

In August 2016 and January 2017, TURN, ORA and Indicated Shippers filed applications for rehearing of the phase one and phase two decisions, respectively. The Utility cannot predict when or if the CPUC will grant the rehearings or if it will adopt the parties' recommendations. Additionally, in June 2017, the Utility filed a PFM of the phase one decision to eliminate the requirement that the Utility install new cathodic protection systems in 2018 because the Utility is not in a position to identify the optimal location for such new systems in 2018. Instead, the Utility requested to be allowed to continue its current cathodic protection program. As directed by the CPUC, on August 23, 2017, the Utility provided supplemental information to the CPUC regarding the PFM. The Utility is unable to predict if and when the CPUC would adopt the PFM. In the event the PFM is not adopted and the Utility fails to perform the mandated new cathodic protection systems, the Utility could incur fines and penalties, the amount of which the Utility is unable to predict.

***2019 Gas Transmission and Storage Rate Case***

On November 17, 2017, the Utility filed its 2019 GT&S rate case application with the CPUC, covering the years 2019 through 2021. While the Utility has not formally proposed a fourth year for this rate case, it provided a revenue requirement and rates for 2022, in the event the CPUC adopts an additional year.

In its application, the Utility requested that the CPUC authorize a 2019 revenue requirement of $1.59 billion to recover anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2019. This corresponds to an increase of $289 million over the Utility's 2018 authorized revenue requirement of $1.30 billion. The Utility's request also includes proposed revenue requirements of $1.73 billion for 2020, $1.91 billion for 2021, and $1.91 billion for 2022 if the CPUC orders a fourth year for the rate case period.

The requested rate base for 2019 is $4.66 billion, which corresponds to an increase of $0.95 billion over the 2018 authorized rate base of $3.71 billion. These rate base amounts exclude approximately $576 million of capital spending subject to audit by the CPUC related to 2011 through 2014 expenditures in excess of amounts adopted in the 2011 GT&S rate case. The Utility is unable to predict whether the $576 million, or a portion thereof, will ultimately be authorized by the CPUC and included in the Utility's future rate base. The Utility's request also excludes rate base adjustments that the Utility requested with the CPUC on November 14, 2017, resulting from the IRS's October 5, 2017 private letter ruling issued in connection with the CPUC's final phase two decision in the 2015 GT&S rate case. The Utility's request is based on capital expenditure forecasts of $971 million for 2019, $963 million for 2020, and $804 million for 2021 (which exclude common capital allocations).

The increase in revenue requirement is largely attributable to increased infrastructure investment and costs related to new natural gas storage safety and environmental regulations. Such new regulations were issued by: (1) the DOGGR, which issued six new safety and reliability natural gas storage measures in 2016 in response to the 2015 Southern California natural gas storage leak in Aliso Canyon; (2) the PHMSA, which issued interim final rules, effective January 18, 2017, that address pipeline safety issues and mandate certain reporting requirements for operators of underground natural gas storage facilities; and (3) the CPUC, which issued General Order 112-F that became effective on January 1, 2017, and requires additional expenditures in the areas of gas leak repair, leak survey, and high consequence area identification, among other things.

In addition, DOGGR is planning to complete its final rulemaking on new gas storage safety rules. The draft rules, that were released for comments on May 19, 2017, include a requirement for natural gas storage operators to perform well integrity assessments every two years and to eliminate possible single points of failure from natural gas storage wells. The implementation timeframe and requirements under the PHMSA's proposed regulations currently are being challenged in federal courts. In its application, the Utility proposes a new two-way Gas Storage Balancing Account to address uncertainty around the anticipated DOGGR regulations, and also proposes a new memorandum account to track costs related to other anticipated new regulations.

As a result of the existing and anticipated gas storage safety requirements, the Utility developed and proposed in its 2019 GT&S rate case application a natural gas storage strategy which includes the discontinuation (through closure or sale) of operations at two gas storage fields. The discontinuation is expected to reduce long-term costs for customers and to reduce safety and environmental risks.

In addition to costs related to new natural gas storage safety and environmental regulations, the Utility proposed increased infrastructure investments over the 2019 to 2021 period to continue its efforts to improve overall system safety by: (1) making approximately 1,100 miles of transmission pipelines capable of in-line inspection; (2) performing in-line inspections of over 2,100 miles of transmission pipeline, or approximately one-third of total miles; (3) testing or replacing all pipeline without a test record (or with a test record that does not meet the Utility's documentation requirements) by 2027; (4) replacing vintage pipeline for other safety or reliability issues; and (5) automating valves in areas where there is a significant potential impact.

A prehearing conference took place on January 4, 2018, and established a procedural schedule. Testimony will be served near the end of second quarter of 2018 and evidentiary hearings, if needed, will begin in the third quarter of 2018. As stated above, the Utility expects to file an update of its revenue requirement forecast to reflect the Tax Act by the end of March 2018.

**Transmission Owner Rate Cases**

*Transmission Owner Rate Case for 2017 (the "TO18 rate case")*

On July 29, 2016, the Utility filed its TO18 rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of $1.72 billion, a $387 million increase over the 2016 revenue requirement of $1.33 billion. The forecasted network transmission rate base for 2017 is $6.7 billion. The Utility is also seeking a return on equity of 10.9%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted that it will make investments of $1.30 billion in 2017 in various capital projects.

On September 30, 2016, the FERC issued an order accepting the Utility's July 2016 filing and set it for hearing, but held the hearing procedures in abeyance for settlement procedures. The order set an effective date for rates of March 1, 2017, and made the rates subject to refund following resolution of the case. On March 17, 2017, the FERC chief judge issued an order terminating the settlement procedures due to an impasse in the settlement negotiations reported by the parties.

On August 22, 2017, the FERC trial staff submitted testimony. The table below summarizes the differences between the amount of revenue requirement increases included in the Utility's request and the testimony submitted by the FERC trial staff:

| (in millions) | Amounts requested by the Utility | Amounts proposed by the FERC trial staff |
|---|---|---|
| Revenue Requirement | $ 1,718 | $ 1,353 |
| Return on Equity | 10.90% | 8.46% |
| Composite Depreciation Rate | 3.26% | 2.08% |

Additionally, intervenors provided testimony on July 5, 2017 and the Utility submitted rebuttal testimony on October 9, 2017. Hearings in this proceeding took place January 9 through January 30, 2018, and an initial decision is expected on or before June 1, 2018.

Also, on March 31, 2017, several of the parties that had already intervened in the TO18 rate case filed a complaint at the FERC, and requested that the complaint be consolidated with the rate case. The complaint asserts that the Utility's revenue requirement request in TO18 is unreasonably high and should be reduced. The complaint asks that, if the outcome of the litigation in TO18 is that the Utility's revenue requirement should be set at a lower level than the revenue requirement from the TO17 settlement, that the FERC order refunds to that lower level determined in TO18 litigation. On April 20, 2017, the Utility answered the complaint, requesting that FERC dismiss it. On November 16, 2017, FERC dismissed the complaint as the Utility had requested. On December 18, 2017, the complainants filed a request for rehearing of that order, and on January 16, 2018, FERC issued an order granting rehearing for further consideration. That order does not address the merits of the complaint; it simply gives FERC more time to reconsider its prior order dismissing the complaint. The Utility is unable to predict when FERC may issue an order on the merits of the complaint.

*Transmission Owner Rate Case for 2018 (the "TO19 rate case")*

On July 27, 2017, the Utility filed its TO19 rate case at the FERC requesting a 2018 retail electric transmission revenue requirement of $1.79 billion, a $74 million increase over the proposed 2017 revenue requirement of $1.72 billion. The forecasted network transmission rate base for 2018 is $6.9 billion. The Utility is also seeking an ROE of 10.75%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted capital expenditures of approximately $1.4 billion. On September 28, 2017, the FERC issued an order accepting the Utility's July 2017 filing, subject to hearing and refund, and established March 1, 2018, as the effective date for rate changes. The next settlement conference is scheduled for May 16, 2018. FERC also ordered that the hearings will be held in abeyance pending settlement discussion among the parties.

On September 29, 2017, several of the parties that have intervened in the TO19 rate case filed a complaint at the FERC, and requested that the complaint be consolidated with the TO19 rate case. The complaint asserts that the Utility's revenue requirement request in TO19 is unreasonably high and should be reduced. The complaint asks that, if the outcome of the litigation in TO19 is that the Utility's revenue requirement should be set at a lower level than the settled revenue requirement approved by FERC in TO17, FERC order refunds to that lower level determined in the TO18 litigation. On October 17, 2017, the Utility answered the complaint, requesting that FERC dismiss it. The Utility is unable to predict when and how the FERC will respond to the complaint.

*Transmission Owner Rate Cases for 2015 and 2016 (the "TO16" and "TO17" rate cases)*

On January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion reversing FERC's decisions in the TO16 and TO17 rate cases to grant the Utility a 50 basis point ROE incentive adder for continued participation in the CAISO. The decision has been remanded to FERC for further proceedings consistent with the Court of Appeals' opinion. If FERC makes findings consistent with the Ninth Circuit Court of Appeals' opinion, the Utility would incur a refund obligation of $1 million and $8.5 million for TO16 and TO17, respectively. Alternatively, if FERC again concludes that the Utility should receive the 50 basis point ROE incentive adder and provides the additional explanation that the Ninth Circuit found the FERC's prior decisions lacked, then the Utility would not owe any refunds for this issue for TO16 or TO17. The Utility is unable to predict the outcome and timing of FERC's response to this opinion.

**Diablo Canyon Nuclear Power Plant**

*Joint Proposal for Plant Retirement*

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application implements a joint proposal between the Utility and the Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and Alliance for Nuclear Responsibility (together, the "Joint Parties").

On January 11, 2018, the CPUC issued a final decision in the Utility's proposal to retire Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025. The CPUC also:

- deferred consideration of replacement resources to the CPUC's Integrated Resource Planning proceeding;
- authorized rate recovery for up to $211.3 million (compared with the $352.1 million requested by the Utility) for an employee retention program;
- authorized rate recovery for an employee retraining program of $11.3 million requested by the Utility;
- rejected rate recovery of the proposed $85 million for the community impacts mitigation program on the ground that rate recovery for such a program requires legislative authorization;
- authorized rate recovery of $18.6 million of the total Diablo Canyon license renewal cost of $53 million and rate recovery of cancelled project costs equal to 100% of direct costs incurred prior to June 30, 2016, and 25% of direct costs incurred after June 30, 2016, based on a settlement agreement among the Utility, the Joint Parties, and certain other parties that the Utility filed with the CPUC in May 2017; and
- approved the amortization of the book value for Diablo Canyon consistent with the Diablo Canyon closure schedule.

During the year ended December 31, 2017, the Utility incurred pre-tax charges of $47 million related to the retirement of Diablo Canyon including $24 million for cancelled projects and $23 million for disallowed license renewal costs. The Utility does not expect to incur additional charges as a result of the CPUC's final decision, other than additional project cancellation costs that the Utility does not expect to be material.

The Joint Parties determined that they will not seek a rehearing on the CPUC final decision. In accepting the CPUC's decision to retire Diablo Canyon, the Utility will withdraw its license renewal application at the NRC.

*California State Lands Commission Lands Lease*

On June 28, 2016, the California State Lands Commission approved a new lands lease for the intake and discharge structures at Diablo Canyon to run concurrently with Diablo Canyon's current operating licenses, until Diablo Canyon Unit 2 ceases operations in August 2025. The Utility believes that the approval of the new lease will ensure sufficient time for the Utility to identify and bring online a portfolio of GHG-free replacement resources. The Utility will submit a future lease extension request to address the period of time required for plant decommissioning, which under NRC regulations can take as long as 60 years. On August 28, 2016, the World Business Academy filed a writ in the Los Angeles Superior Court asserting that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act and alleging that the State Lands Commission should be required to perform an environmental review of the new lands lease. The trial took place on July 11, 2017, in Los Angeles Superior Court and the judge dismissed the petition on all grounds, ruling that the State Lands Commission properly determined the short term lease extension was subject to the existing facilities exemption under the California Environmental Quality Act. The World Business Academy appealed this decision and the matter is currently before the California Court of Appeals in Los Angeles, Second District. The trial date has not been set.

*Asset Retirement Obligations*

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

While the NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the final decision's employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program described above. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study to the CPUC by mid-2019. The Utility expects to file its 2018 NDCTP application in late 2018 or early 2019. (See "Asset Retirement Obligations" in Note 2 to the Consolidated Financial Statements in Item 8.)

**CPUC Cost of Capital**

On July 13, 2017, the CPUC issued a final decision adopting, with no modifications to it, the PFM filed in February 2017 by San Diego Gas & Electric Company, Southern California Gas Company, Southern California Edison, the ORA, TURN, and the Utility.

The final decision extends the Utility's next cost of capital application filing deadline by two years to April 22, 2019, for the year 2020. The final decision also reduces the Utility's authorized ROE from 10.40% to 10.25%, effective January 1, 2018, and resets the Utility's authorized cost of long-term debt and preferred stock effective January 1, 2018. In addition, the decision suspends the cost of capital adjustment mechanism to adjust cost of capital for 2018, but allows the adjustment mechanism to operate for 2019 if triggered. If the mechanism is activated for 2019, the Utility's cost of capital, including its new ROE of 10.25%, will be adjusted according to the existing terms of the mechanism. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity remains unchanged.

The final decision also leaves the proceeding open to facilitate gathering of information to inform the next cost of capital proceeding, as well as to provide a possible venue in which to consider whether the Utility's ROE should be reduced until any recommendations that the CPUC may adopt in the second phase of its safety culture investigation are implemented, as described in the May 8, 2017 scoping memo and ruling issued in the Safety Culture OII.

On September 29, 2017, the Utility submitted an advice letter to the CPUC, updating its cost of capital and the estimated revenue requirement impacts with an effective date of January 1, 2018. The long-term debt cost, reset to 4.89%, reflects actual embedded costs as of the end of August 2017 and forecasted interest rates for the new long-term debt expected to be issued for the remainder of 2017 and all of 2018. Changes in market interest rates may have material effects on the cost of the Utility's future financings, but will not affect the authorized cost of capital in 2018.

The Utility expects to file its next cost of capital application in 2019.

**Application to Establish a Wildfire Expense Memorandum Account**

On July 26, 2017, the Utility filed an application with the CPUC requesting to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date. Concurrently with this application, the Utility also submitted a motion to the CPUC requesting that the WEMA be deemed effective as of July 26, 2017, such that the Utility may begin recording costs to the account while the application is pending before the CPUC.

Under the WEMA as proposed, the Utility would record costs related to wildfires, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by the Utility but excluding costs that have already been authorized in the Utility's GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, would be credited to the WEMA as they are received. The WEMA would not include the Utility's costs for fire response and infrastructure costs which are tracked in CEMA. The Utility would be required to file an application to seek approval to recover costs tracked in WEMA. A prehearing conference was held on December 8, 2017, and a scoping memo was issued on January 11, 2018. The Utility filed opening briefs with the CPUC on January 25, 2018 and other parties' briefs are expected to be filed in February 2018. The Utility cannot predict the outcome of this proceeding.

**Catastrophic Event Memorandum Account Applications**

The CPUC allows utilities to recover the reasonable, incremental costs of responding to catastrophic events through a CEMA. The CEMA tariff authorizes the utilities to recover costs incurred in connection with a catastrophic event that has been declared a disaster or state of emergency by competent federal or state authorities. In 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. The costs associated with this work were tracked in the CEMA. While the Utility believes such costs are recoverable through CEMA, its CEMA applications are subject to CPUC approval.

In 2016, the Utility submitted a request to the CPUC to authorize recovery under the CEMA tariff revenue requirement of approximately $146 million for recorded capital and expense costs related to drought mitigation and emergency response activities for declared disasters that occurred from December 2012 through March 2016. On January 4, 2018, ORA, TURN, and the Utility filed an all-party motion with the CPUC seeking approval of a settlement agreement these parties have entered into. The settlement agreement proposes that the Utility's total CEMA tariff revenue requirement request be reduced by $29 million, from $146 million to $117 million. The Utility has requested that these costs be recovered through rates in 2018 and 2019. PG&E Corporation and the Utility are unable to predict the outcome of this proceeding.

The Utility expects to submit its 2018 CEMA application to the CPUC in the second quarter of 2018.

**Other Regulatory Proceedings and Initiatives**

*Electric Distribution Resources Plan*

As required by California law, on July 1, 2015, the Utility filed its proposed DRP for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of DERs. The Utility's proposal is designed to allow energy technologies to be integrated into the larger grid while continuing to provide customers with safe, reliable, and affordable electric service.

On February 27, 2017, the CPUC issued a ruling that seeks the development of a process for incorporating DER forecasts into the DRP that takes into consideration the coordination with other statewide planning and forecasting processes such as the CEC's Integrated Energy Policy Report. This ruling mandated the Utility, along with the other California IOUs, to develop a draft joint proposal for the CPUC and stakeholder consideration on the process for developing DER forecasts. On June 9, 2017, the IOUs submitted a draft joint proposal for CPUC and stakeholder consideration. The CPUC issued a PD on December 8, 2017, requiring the IOUs to use the CEC's DER forecast for the 2018-2019 distribution planning cycle. The Utility has historically used the CEC forecast for planning and will have the opportunity to adjust forecasts for EV, photovoltaic, and energy storage during the intermediate years. The PD also requires the IOUs to develop an alternate planning forecast scenario in 2018 to establish a method for calculating costs and benefits for DER grid integration to better inform DER sourcing policies. Workshops to discuss the joint proposal will continue in early 2018 and a final decision is expected from the CPUC by the end of the first quarter of 2018.

On June 30, 2017, the CPUC issued another ruling soliciting stakeholder responses on questions set forth in a CPUC staff white paper on proposing a DIDF. The DIDF aims to establish a process for identifying distribution deferral opportunities for DERs. Stakeholder comments on DIDF were submitted on August 7, 2017, with reply comments submitted on August 18, 2017. On December 8, 2017, the CPUC issued a PD requiring an annual grid needs assessment and an annual distribution deferral opportunity report, as part of the annual DRP for greater transparency on infrastructure investments. The grid needs assessment report will identify critical overload areas on the grid. The distribution deferral opportunity report will document the Utility's proposed distribution needs and identify DER deferral opportunities to be reviewed by the Distribution Planning Advisory Group for prioritizing DER deferral projects. The PD proposes to adopt the regulatory incentive mechanism being piloted in the Integrated Distributed Energy Resources Proceeding where the Utility can earn a 4% pre-tax incentive on the annual payments for DER deferral contracts. The Utility expects a final decision from the CPUC in the first quarter of 2018.

*Integrated Distributed Energy Resources Proceeding - Regulatory Incentives Pilot Program*

On April 4, 2016, the CPUC issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective DERs. The ruling stated that it did not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities. On December 22, 2016, the CPUC issued a final decision in the proceeding which authorizes a pilot to test a regulatory incentive mechanism through which the Utility will earn a 4% pre-tax incentive on annual payments for DERs, as well as test a regulatory process that will allow the Utility to competitively solicit DER services to defer distribution infrastructure. Each IOU is required to conduct at least one pilot, but may conduct up to three additional pilots.

In June 2017, the Utility submitted a pilot project proposal to the CPUC for approval to begin solicitations. The pilot aims to evaluate the effectiveness of an earnings opportunity in motivating utilities to source DERs. On October 27, 2017, the CPUC issued a draft resolution that proposed modifications to the Utility's pilot program. On December 14, 2017, the CPUC granted the Utility's November 20, 2017 request to cancel the current pilot project proposal due to the damage of the Utility's facilities in the area of the Northern California wildfires and propose a new pilot program location by May 1, 2018.

*2015 - 2016 Energy Efficiency Incentive Awards*

On December 14, 2017, the CPUC approved a final 2015 - 2016 energy savings performance incentive award of $21.9 million, compared to the Utility's request of $24.7 million. The award was fully offset by a portion of the remaining reduction approved in the settlement agreement related to the rehearing of the 2006 - 2008 risk/reward incentive mechanism. The settlement agreement requires the Utility to reduce future energy efficiency shareholder incentives by a total of $29.1 million, of which $5.8 million was used to offset the 2014 - 2015 award. The remaining settlement reduction of $1.3 million will be offset against future energy saving performance incentive awards.

**LEGISLATIVE AND REGULATORY INITIATIVES**

The California Legislature and the CPUC have adopted requirements, policies, and decisions to implement new state law requirements applicable to natural gas storage facilities, accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, improve fire safety regulations, and foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, and reduce cross-subsidization among customer rate classes. CPUC proceedings related to some of these matters are discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

*Power Charge Indifference Adjustment OIR*

On April 25, 2017, the Utility, along with Southern California Edison Company and San Diego Gas & Electric Company, filed a joint application with the CPUC on how to allocate costs associated with long-term power commitments in a manner that ensures all customers are treated equally. At issue is how customers within communities that choose to implement CCA power arrangements and those served under direct access pay for their share of the costs. The utilities believe that these customers are not paying their full share of costs associated with the long-term commitments, which results in other customers paying more, which is inconsistent with state law. The Utility is committed to helping create a cost allocation method that treats all customers fairly and equally, whether they continue to receive service from the Utility or choose a CCA or direct access provider. The Utility projects that more than half of its customers will purchase electricity from a CCA or direct access provider by 2020. Without changes to the current cost allocation system, a portion of the contract and facilities costs will be shifted to customers who remain with the Utility or live in areas that do not have access to alternative electricity providers. The utilities' joint proposed approach would replace the current system, which is known as the PCIA, with an updated system known as the Portfolio Allocation Methodology.

On June 29, 2017, the CPUC dismissed the Utility's joint Portfolio Allocation Methodology application without prejudice and instead approved an OIR to review, revise, and consider alternatives to the PCIA. The OIR will focus on PCIA within the larger context of consumer choice in energy services, and should not be considered a follow-up to the CPUC and Energy Commission Joint En Banc on Customer Choice in California. On September 25, 2017, the CPUC issued a scoping memo and ruling establishing a procedural schedule and a new overall goal to mitigate cost increases for both bundled and departing load customers. Testimony is scheduled for the first quarter of 2018. Evidentiary hearings, if needed, are scheduled for the second quarter of 2018 and a proposed decision is expected by the third quarter of 2018.

*Customer Choice*

On May 19, 2017, California energy companies, along with other stakeholders discussed customer choice and the future of California's electric industry at a CPUC "en banc" meeting. Specifically, the goal of the meeting was to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy and to lay out elements of a path forward to ensure that California achieves its reliability, affordability, equity, and carbon reduction imperatives while recognizing the important role that technology and customer preferences will play in shaping this future.

On October 11, 2017, the CPUC announced the formation of the California Customer Choice Project to examine the issues and produce a report evaluating regulatory framework options in early 2018. The CPUC held an informal public workshop on October 31, 2017, to gather stakeholder input on global and national electric market choice models, including California's 2020 market. The project may produce a white paper that will provide a framework to evaluate customer choice models based on affordability, decarbonization, and reliability. The white paper will not present a recommendation nor is it intended to provide the basis for instituting a rulemaking. While the CPUC had indicated its intent to open a proceeding related to customer choice, the Utility is unable to predict whether that remains the CPUC's intent or the timing of any such proceeding.

*Electric Vehicle (EV) Infrastructure Development*

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain EV charging stations and the associated infrastructure. On December 15, 2016, the CPUC issued a final decision establishing a three-year EV program of $130 million (approximately $109 million in capital expenditures) to deploy up to 7,500 charging stations. Further deployment of light-duty EV infrastructure will be considered in a second phase of the proceeding.

*Transportation Electrification (TE)*

California Law (SB 350) requires the CPUC, in consultation with the CARB and the CEC, to direct electrical corporations to file applications for programs and investments to accelerate widespread TE. In September 2016, the CPUC directed the Utility and the other large IOUs to file TE applications which include both short-term projects (of up to $20 million in total) and two- to five-year programs with a requested revenue requirement determined by the Utility. On January 20, 2017, the Utility filed its TE application with the CPUC requesting a total of up to $253 million (approximately $211 million in capital expenditures) in program funding over five years (2018 - 2022) related to make-ready infrastructure for TE in medium to heavy-duty vehicle sectors, fast charging stations, and short-term projects which includes a series of TE demonstration projects and pilot programs. On January 11, 2018, the CPUC approved, with modifications, four out of the five short-term projects proposed by the Utility for a total of approximately $8 million. The CPUC may issue a proposed decision on the make-ready infrastructure proposals in the first or second quarter of 2018.

*Fire Safety OIR*

On December 14, 2017, the CPUC approved new regulations to enhance the fire safety of overhead electric transmission and distribution lines located in high fire-threat areas. This is the culmination of a decade-long effort to improve the fire safety of overhead utility and communication infrastructure across California. The SED conferred with Cal Fire, California IOUs, and fire safety professionals, to develop and adopt a statewide fire-threat map. This map, in conjunction with a United States Forest Service and Cal Fire map of tree mortality high hazard zones, will dictate the application of the new fire safety regulations. On January 19, 2018, the CPUC approved the final fire safety map associated with the new regulations.

The new regulations include increased patrol frequency for overhead facilities, expanded vegetation clearances around powerlines, and give the utilities increased authority to de-energize lines on private property for the removal of trees that pose an immediate threat to fire safety. The costs associated with the implementation of these new regulations will be tracked in a fire hazard prevention memorandum account and requested for recovery through rates.

**ENVIRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of $CO_2$ and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Item 1A. Risk Factors, "Environmental Regulation" in Item 1. and "Environmental Remediation Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**RISK MANAGEMENT ACTIVITIES**

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e. risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

**Commodity Price Risk**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs in its gas transmission and storage rate cases through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $8 million and $7 million at December 31, 2017 and 2016, respectively. During 2017, the Utility's approximate high, low, and average values-at-risk were $8 million, $7 million and $7 million, respectively. During 2016, the value-at-risk amounts were $7 million, $1 million and $4 million, respectively. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.)

**Interest Rate Risk**

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2017 and 2016, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be $12 million and $13 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of interest rates.)

**Energy Procurement Credit Risk**

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's energy procurement credit risk exposure to its counterparties:

| (in millions) | Gross Credit Exposure Before Credit Collateral (1) | Credit Collateral | Net Credit Exposure (2) | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| December 31, 2017 | $ 40 | $ (16) | $ 24 | 2 | 12 |
| December 31, 2016 | $ 69 | $ (11) | $ 58 | 3 | 39 |

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.
(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.



**CRITICAL ACCOUNTING POLICIES**

The preparation of the Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates and assumptions. These accounting policies and their key characteristics are outlined below.

**Regulatory Accounting**

As a regulated entity, the Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2017, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $5.6 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $9.9 billion.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods presented. If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. If regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on its best estimate; to the extent there is a high degree of uncertainty in the Utility's forecast, it will record a provision based on the lower end of the range of possible losses. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

In 2017, the Utility recorded charges of $47 million for capital expenditures related to cancelled projects and disallowed license renewal costs as part of the Diablo Canyon settlement agreement. In 2016, the Utility incurred charges of $283 million and $219 million for capital spending that was disallowed related to the San Bruno Penalty Decision and for capital expenditures disallowed based on the final phase two decision in its 2015 GT&S rate case, respectively. In 2015, the Utility incurred charges of $407 million for capital spending that were disallowed related to the San Bruno Penalty Decision. The Utility would be required to record charges in future periods to the extent there are additional capital disallowances. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**Loss Contingencies**

As discussed below, PG&E Corporation and the Utility have recorded material accruals for various enforcement and legal matters and environmental remediation liabilities. PG&E Corporation and the Utility have also recorded insurance receivables for third-party claims.

***Enforcement and Litigation Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. Actual results may differ materially from these estimates and assumptions. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

***Environmental Remediation Liabilities***

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former manufactured gas plant sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2017 and 2016, the Utility's accruals for undiscounted gross environmental liabilities were $1 billion and $958 million, respectively. The Utility's undiscounted future costs could increase to as much as $2.1 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Insurance Receivable***

The Utility has liability insurance from various insurers, which provides coverage for third party claims. The Utility records insurance recoveries only when a third party claim is recorded and it is deemed probable that a recovery of that claim will occur and the Utility can reasonably estimate the amount or its range. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex judgments about future events. Insurance recoveries are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, including contractual liability insurance policy coverage, advice of legal counsel, past experience with similar events, discussions with insurers and other information and events pertaining to a particular matter. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**Asset Retirement Obligations**

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

To estimate its liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2017, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $4.9 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Adjustments to the pension and other benefit obligation are based on the differences between actuarial assumptions and actual plan results. These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2018 is 6.8%, gradually decreasing to the ultimate trend rate of 4.5% in 2027 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 6.2% compares to a ten-year actual return of 7.8%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 623 Aa-grade non-callable bonds at December 31, 2017. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2017 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2017 |
|---|---|---|---|
| Discount rate | (0.50) % | $ 111 | $ 1,485 |
| Rate of return on plan assets | (0.50) % | 73 | - |
| Rate of increase in compensation | 0.50 % | 61 | 348 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2017 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2017 |
|---|---|---|---|
| Health care cost trend rate | 0.50 % | $ 4 | $ 63 |
| Discount rate | (0.50) % | 4 | 142 |
| Rate of return on plan assets | (0.50) % | 10 | - |

**NEW ACCOUNTING PRONOUNCEMENTS**

See Note 2 of the Notes to the Consolidated Financial Statements.

**FORWARD-LOOKING STATEMENTS**

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the impact of the Northern California wildfires, including the costs of restoration of service to customers and repairs to the Utility's facilities, and whether the Utility is able to recover such costs through CEMA; the timing and outcome of the wildfire investigations, including into the causes of the wildfires; whether the Utility may have liability associated with these fires; if liable for one or more fires, whether the Utility would be able to recover all or part of such costs through insurance or through regulatory mechanisms, to the extent insurance is not available or exhausted; and potential liabilities in connection with fines or

penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;



- the impact of the Tax Act, and the timing and outcome of the CPUC decision related to the Utility's future filings in connection with the impact of the Tax Act on the Utility's rate cases and its implementation plan;
- the Utility's ability to efficiently manage capital expenditures and its operating and maintenance expenses within the authorized levels of spending and timely recover its costs through rates, and the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs;
- the timing and outcomes of the 2019 GT&S rate case, TO18 and TO19 rate cases and other ratemaking and regulatory proceedings;
- the timing and outcome of the Butte fire litigation, the timing and outcome of any proceeding to recover costs in excess of insurance from customers, if any; the effect, if any, that the SED's $8.3 million citations issued in connection with the Butte fire may have on the Butte fire litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Utility;
- whether the CPUC approves the Utility's application to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date, and the outcome of any potential request to recover such costs;
- the outcome of the probation and the monitorship imposed by the federal court after the Utility's conviction in the federal criminal trial in 2017, the timing and outcomes of the debarment proceeding, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility's compliance with natural gas- and electric- related laws and regulations, ex parte communications, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;
- the timing and outcomes of investigations by the U.S. Attorney's Office in San Francisco and the California Attorney General's office related to communications between the Utility's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in the Utility's ratemaking proceedings;
- the effects on PG&E Corporation and the Utility's reputations caused by the Utility's conviction in the federal criminal trial in 2017, the state and federal investigations of natural gas incidents and the Northern California wildfires, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;
- whether the Utility can control its costs within the authorized levels of spending, and successfully implement a streamlined organizational structure and achieve project savings, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;
- whether the Utility is able to successfully adapt its business model to significant change that the electric industry is undergoing and the impact such change will have on the natural gas industry;
- the impact of increased costs to comply with natural gas regulations, including the SB 887 directing DOGGR and CARB to develop permanent regulations for gas storage facility operations in California to comply with new safety and reliability measures, the PHMSA rules effective January 18, 2017 regulating gas storage facilities at the federal level; and the CPUC General Order 112-F that went into effect on January 1, 2017, that requires additional expenditures in the areas of gas leak repair, leak survey, high consequences area identification, and operator qualifications, and could impact the Utility's ability to timely recover such costs;

- whether the Utility and its third-party vendors and contractors are able to protect the Utility's operational networks and information technology systems from cyber- and physical attacks, or other internal or external hazards;
- the timing and outcome of the complaint filed by the CPUC and certain other parties with the FERC on February 2, 2017 that requests that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the CAISO's Transmission Planning Process to allow for greater participation and input from interested parties; and the timing and ultimate outcome of the Ninth Circuit Court of Appeals decision on January 8, 2018, to reverse FERC's decision granting PG&E a 50 basis point ROE incentive adder for continued participation in the CAISO and remanding the case to FERC for further proceedings;
- the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;
- the outcome of the safety culture OII, including its phase two proceeding opened on May 8, 2017, and future legislative or regulatory actions that may be taken, such as requiring the Utility to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or implement corporate governance changes;
- the outcome of current and future self-reports, investigations or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cyber security, environmental laws and regulations; and the outcome of notices of violations in connection with the Yuba City incident;
- the outcomes of the CPUC's data requests and future PDs, including in connection with the Utility's SmartMeter™ Upgrade cost-benefit analysis, and of the Utility's PFMs, including in connection with the installation of new cathodic protection systems in 2018;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;
- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon; whether the Utility will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees as a result of its planned retirement by 2024 and 2025;
- the impact of wildfires, droughts, floods, or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and the reparation and other costs that the Utility may incur in connection with such conditions or events; the impact of the adequacy of the Utility's emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and sufficient to cover the Utility's liability;
- the breakdown or failure of equipment that can cause fires and unplanned outages; and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;
- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, EVs, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;
- whether the Utility's climate change adaptation strategies are successful;
- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing the Utility's procurement service for CCAs;
- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;
- whether, as a result of Westinghouse's Chapter 11 proceeding and its planned purchase by Brookfield Business Partners L.P., the Utility will experience issues with nuclear fuel supply, nuclear fuel inventory, and related services and products that Westinghouse supplies, and whether such proceeding will affect the Utility's contracts with Westinghouse;
- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;
- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;
- changes in credit ratings which could, among other things, result in higher borrowing costs and fewer financing options, especially if PG&E Corporation or the Utility were to lose their investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the Utility's conviction in the federal criminal trial, and other enforcement matters will impact the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;
- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the new federal administration; and
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see Item 1A. Risk Factors below and a detailed discussion of these matters contained elsewhere in MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "News & Events: Events & Presentations" tab, in order to publicly disseminate such information.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in Item 7. MD&A and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.



**ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Operating Revenues** | | | |
| Electric | $ 13,124 | $ 13,864 | $ 13,657 |
| Natural gas | 4,011 | 3,802 | 3,176 |
| **Total operating revenues** | **17,135** | **17,666** | **16,833** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,309 | 4,765 | 5,099 |
| Cost of natural gas | 746 | 615 | 663 |
| Operating and maintenance | 6,270 | 7,354 | 6,951 |
| Depreciation, amortization, and decommissioning | 2,854 | 2,755 | 2,612 |
| **Total operating expenses** | **14,179** | **15,489** | **15,325** |
| **Operating Income** | 2,956 | 2,177 | 1,508 |
| Interest income | 31 | 23 | 9 |
| Interest expense | (888) | (829) | (773) |
| Other income, net | 72 | 91 | 117 |
| **Income Before Income Taxes** | **2,171** | **1,462** | **861** |

| | | | |
|---|---|---|---|
| Income tax provision (benefit) | 511 | 55 | (27) |
| **Net Income** | **1,660** | **1,407** | **888** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 1,646** | **$ 1,393** | **$ 874** |
| **Weighted Average Common Shares Outstanding, Basic** | **512** | **499** | **484** |
| **Weighted Average Common Shares Outstanding, Diluted** | **513** | **501** | **487** |
| **Net Earnings Per Common Share, Basic** | **$ 3.21** | **$ 2.79** | **$ 1.81** |
| **Net Earnings Per Common Share, Diluted** | **$ 3.21** | **$ 2.78** | **$ 1.79** |

See accompanying Notes to the Consolidated Financial Statements.



**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Net Income** | **$ 1,660** | **$ 1,407** | **$ 888** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $1, and $0, at respective dates) | 1 | (2) | (1) |
| Net change in investments (net of taxes of $0, $0, and $12 at respective dates) | - | - | (17) |
| **Total other comprehensive income (loss)** | **1** | **(2)** | **(18)** |
| **Comprehensive Income** | **1,661** | **1,405** | **870** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 1,647** | **$ 1,391** | **$ 856** |

See accompanying Notes to the Consolidated Financial Statements.



**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 449 | $ 177 |

| | | |
|---|---|---|
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $64 and $58 at respective dates) | 1,243 | 1,252 |
| Accrued unbilled revenue | 946 | 1,098 |
| Regulatory balancing accounts | 1,222 | 1,500 |
| Other | 861 | 801 |
| Regulatory assets | 615 | 423 |
| Inventories | | |
| Gas stored underground and fuel oil | 115 | 117 |
| Materials and supplies | 366 | 346 |
| Income taxes receivable | - | 160 |
| Other | 464 | 290 |
| **Total current assets** | **6,281** | **6,164** |
| **Property, Plant, and Equipment** | | |
| Electric | 55,133 | 52,556 |
| Gas | 19,641 | 17,853 |
| Construction work in progress | 2,471 | 2,184 |
| Other | 3 | 2 |
| **Total property, plant, and equipment** | **77,248** | **72,595** |
| Accumulated depreciation | (23,459) | (22,014) |
| **Net property, plant, and equipment** | **53,789** | **50,581** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 3,793 | 7,951 |
| Nuclear decommissioning trusts | 2,863 | 2,606 |
| Income taxes receivable | 65 | 70 |
| Other | 1,221 | 1,226 |
| **Total other noncurrent assets** | **7,942** | **11,853** |
| **TOTAL ASSETS** | **$ 68,012** | **$ 68,598** |

See accompanying Notes to the Consolidated Financial Statements.



**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 931 | $ 1,516 |
| Long-term debt, classified as current | 445 | 700 |
| Accounts payable | | |
| Trade creditors | 1,646 | 1,495 |
| Regulatory balancing accounts | 1,120 | 645 |

| | | |
|---|---|---|
| Other | 517 | 433 |
| Disputed claims and customer refunds | 243 | 236 |
| Interest payable | 217 | 216 |
| Other | 2,010 | 2,323 |
| **Total current liabilities** | **7,129** | **7,564** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 17,753 | 16,220 |
| Regulatory liabilities | 8,679 | 6,805 |
| Pension and other postretirement benefits | 2,128 | 2,641 |
| Asset retirement obligations | 4,899 | 4,684 |
| Deferred income taxes | 5,822 | 10,213 |
| Other | 2,130 | 2,279 |
| **Total noncurrent liabilities** | **41,411** | **42,842** |
| **Commitments and Contingencies (Note 13)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 514,755,845 and 506,891,874 shares outstanding at respective dates | 12,632 | 12,198 |
| Reinvested earnings | 6,596 | 5,751 |
| Accumulated other comprehensive loss | (8) | (9) |
| **Total shareholders' equity** | **19,220** | **17,940** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **19,472** | **18,192** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 68,012** | **$ 68,598** |

See accompanying Notes to the Consolidated Financial Statements.



**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,660 | $ 1,407 | $ 888 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,854 | 2,755 | 2,612 |
| Allowance for equity funds used during construction | (89) | (112) | (107) |
| Deferred income taxes and tax credits, net | 1,254 | 1,030 | 693 |
| Disallowed capital expenditures | 47 | 507 | 407 |
| Other | 307 | 379 | 326 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | 67 | (473) | (177) |
| Butte-related insurance receivable | (21) | (575) | - |

| | | | |
|---|---|---|---|
| Inventories | (18) | (24) | 37 |
| Accounts payable | 173 | 180 | (55) |
| Butte-related third-party claims | (129) | 690 | - |
| Income taxes receivable/payable | 160 | (5) | 43 |
| Other current assets and liabilities | 42 | 83 | (288) |
| Regulatory assets, liabilities, and balancing accounts, net | (387) | (1,214) | (244) |
| Other noncurrent assets and liabilities | 57 | (219) | (355) |
| **Net cash provided by operating activities** | **5,977** | **4,409** | **3,780** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,641) | (5,709) | (5,173) |
| Decrease in restricted cash | - | 227 | 64 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,291 | 1,295 | 1,268 |
| Purchases of nuclear decommissioning trust investments | (1,323) | (1,352) | (1,392) |
| Other | 23 | 13 | 22 |
| **Net cash used in investing activities** | **(5,650)** | **(5,526)** | **(5,211)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $5, $6, and $3 at respective dates | (840) | (9) | 683 |
| Short-term debt financing | 750 | 500 | - |
| Short-term debt matured | (500) | - | (300) |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $32, $17 and $27 at respective dates | 2,713 | 983 | 1,123 |
| Long-term debt matured or repurchased | (1,445) | (160) | - |
| Common stock issued | 395 | 822 | 780 |
| Common stock dividends paid | (1,021) | (921) | (856) |
| Other | (107) | (44) | (27) |
| **Net cash provided by financing activities** | **(55)** | **1,171** | **1,403** |
| **Net change in cash and cash equivalents** | **272** | **54** | **(28)** |
| **Cash and cash equivalents at January 1** | **177** | **123** | **151** |
| **Cash and cash equivalents at December 31** | **$ 449** | **$ 177** | **$ 123** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | | | |
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | $ | (790) | $ | (726) | $ | (684) |
| Income taxes, net | | 162 | | 231 | | 77 |
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Common stock dividends declared but not yet paid | $ | - | $ | 248 | $ | 224 |
| Capital expenditures financed through accounts payable | | 501 | | 403 | | 440 |
| Noncash common stock issuances | | 21 | | 20 | | 21 |
| Terminated capital leases | | 23 | | 18 | | - |

See accompanying Notes to the Consolidated Financial Statements.



**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Non controlling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2014** | **475,913,404** | **$ 10,421** | **$ 5,316** | **$ 11** | **$ 15,748** | **$ 252** | **$ 16,000** |
| Net income | - | - | 888 | - | 888 | - | 888 |
| Other comprehensive loss | - | - | - | (18) | (18) | - | (18) |
| Common stock issued, net | 16,112,039 | 801 | - | - | 801 | - | 801 |
| Stock-based compensation amortization | - | 66 | - | - | 66 | - | 66 |
| Common stock dividends declared | - | - | (889) | - | (889) | - | (889) |
| Tax expense from employee stock plans | - | (6) | - | - | (6) | - | (6) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **492,025,443** | **$ 11,282** | **$ 5,301** | **$ (7)** | **$ 16,576** | **$ 252** | **$ 16,828** |
| Cumulative effect of change in accounting principle | - | - | 29 | - | 29 | - | 29 |
| Net income | - | - | 1,407 | - | 1,407 | - | 1,407 |
| Other comprehensive loss | - | - | - | (2) | (2) | - | (2) |
| Common stock issued, net | 14,866,431 | 842 | - | - | 842 | - | 842 |
| Stock-based compensation amortization | - | 74 | - | - | 74 | - | 74 |
| Common stock dividends declared | - | - | (972) | - | (972) | - | (972) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2016** | **506,891,874** | **$ 12,198** | **$ 5,751** | **$ (9)** | **$ 17,940** | **$ 252** | **$ 18,192** |
| Net income | - | - | 1,660 | - | 1,660 | - | 1,660 |
| Other comprehensive income | - | - | - | 1 | 1 | - | 1 |
| Common stock issued, net | 7,863,971 | 416 | - | - | 416 | - | 416 |
| Stock-based compensation amortization | - | 18 | - | - | 18 | - | 18 |
| Common stock dividends declared | - | - | (801) | - | (801) | - | (801) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2017** | **514,755,845** | **$ 12,632** | **$ 6,596** | **$ (8)** | **$ 19,220** | **$ 252** | **$ 19,472** |

See accompanying Notes to the Consolidated Financial Statements.



**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Operating Revenues** | | | |
| Electric | $ 13,127 | $ 13,865 | $ 13,657 |
| Natural gas | 4,011 | 3,802 | 3,176 |
| **Total operating revenues** | **17,138** | **17,667** | **16,833** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,309 | 4,765 | 5,099 |
| Cost of natural gas | 746 | 615 | 663 |
| Operating and maintenance | 6,329 | 7,352 | 6,949 |
| Depreciation, amortization, and decommissioning | 2,854 | 2,754 | 2,611 |
| **Total operating expenses** | **14,238** | **15,486** | **15,322** |
| **Operating Income** | 2,900 | 2,181 | 1,511 |
| Interest income | 30 | 22 | 8 |
| Interest expense | (877) | (819) | (763) |
| Other income, net | 65 | 88 | 87 |
| **Income Before Income Taxes** | **2,118** | **1,472** | **843** |
| Income tax provision (benefit) | 427 | 70 | (19) |
| **Net Income** | **1,691** | **1,402** | **862** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 1,677** | **$ 1,388** | **$ 848** |

See accompanying Notes to the Consolidated Financial Statements.

## Pacific Gas and Electric Company
## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Net Income** | **$ 1,691** | **$ 1,402** | **$ 862** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $3, $1, and $1, at respective dates) | 4 | (1) | (2) |
| **Total other comprehensive income (loss)** | **4** | **(1)** | **(2)** |
| **Comprehensive Income** | **$ 1,695** | **$ 1,401** | **$ 860** |

See accompanying Notes to the Consolidated Financial Statements.



## Pacific Gas and Electric Company
## CONSOLIDATED BALANCE SHEETS
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 447 | $ 71 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $64 and $58 at respective dates) | 1,243 | 1,252 |
| Accrued unbilled revenue | 946 | 1,098 |
| Regulatory balancing accounts | 1,222 | 1,500 |
| Other | 862 | 801 |
| Regulatory assets | 615 | 423 |
| Inventories | | |
| Gas stored underground and fuel oil | 115 | 117 |
| Materials and supplies | 366 | 346 |
| Income taxes receivable | - | 159 |
| Other | 465 | 289 |
| **Total current assets** | **6,281** | **6,056** |
| **Property, Plant, and Equipment** | | |
| Electric | 55,133 | 52,556 |
| Gas | 19,641 | 17,853 |
| Construction work in progress | 2,471 | 2,184 |
| **Total property, plant, and equipment** | **77,245** | **72,593** |
| Accumulated depreciation | (23,456) | (22,012) |
| **Net property, plant, and equipment** | **53,789** | **50,581** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 3,793 | 7,951 |
| Nuclear decommissioning trusts | 2,863 | 2,606 |
| Income taxes receivable | 64 | 70 |

| | | |
|---|---|---|
| Other | 1,094 | 1,110 |
| **Total other noncurrent assets** | **7,814** | **11,737** |
| **TOTAL ASSETS** | **$ 67,884** | **$ 68,374** |

See accompanying Notes to the Consolidated Financial Statements.



**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 799 | $ 1,516 |
| Long-term debt, classified as current | 445 | 700 |
| Accounts payable | | |
| Trade creditors | 1,644 | 1,494 |
| Regulatory balancing accounts | 1,120 | 645 |
| Other | 538 | 453 |
| Disputed claims and customer refunds | 243 | 236 |
| Interest payable | 214 | 214 |
| Other | 2,018 | 2,072 |
| **Total current liabilities** | **7,021** | **7,330** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 17,403 | 15,872 |
| Regulatory liabilities | 8,679 | 6,805 |
| Pension and other postretirement benefits | 2,026 | 2,548 |
| Asset retirement obligations | 4,899 | 4,684 |
| Deferred income taxes | 5,963 | 10,510 |
| Other | 2,146 | 2,230 |
| **Total noncurrent liabilities** | **41,116** | **42,649** |
| **Commitments and Contingencies (Note 13)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 8,505 | 8,050 |
| Reinvested earnings | 9,656 | 8,763 |
| Accumulated other comprehensive income | 6 | 2 |
| **Total shareholders' equity** | **19,747** | **18,395** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 67,884** | **$ 68,374** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,691 | $ 1,402 | $ 862 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,854 | 2,754 | 2,611 |
| Allowance for equity funds used during construction | (89) | (112) | (107) |
| Deferred income taxes and tax credits, net | 1,103 | 1,042 | 714 |
| Disallowed capital expenditures | 47 | 507 | 407 |
| Other | 283 | 306 | 263 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | 66 | (475) | (177) |
| Butte-related insurance receivable | (21) | (575) | - |
| Inventories | (18) | (24) | 37 |
| Accounts payable | 173 | 179 | (2) |
| Butte-related third-party claims | (129) | 690 | - |
| Income taxes receivable/payable | 159 | (29) | 38 |
| Other current assets and liabilities | 59 | 112 | (315) |
| Regulatory assets, liabilities, and balancing accounts, net | (390) | (1,214) | (244) |
| Other noncurrent assets and liabilities | 128 | (219) | (340) |
| **Net cash provided by operating activities** | **5,916** | **4,344** | **3,747** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,641) | (5,709) | (5,173) |
| Decrease in restricted cash | - | 227 | 64 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,291 | 1,295 | 1,268 |
| Purchases of nuclear decommissioning trust investments | (1,323) | (1,352) | (1,392) |
| Other | 23 | 13 | 22 |
| **Net cash used in investing activities** | **(5,650)** | **(5,526)** | **(5,211)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $5, $6, and $3 at respective dates | (972) | (9) | 683 |
| Short-term debt financing | 750 | 500 | - |
| Short-term debt matured | (500) | - | (300) |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $32, $17, and $27 at respective dates | 2,713 | 983 | 1,123 |
| Repayments of long-term debt | (1,445) | (160) | - |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (784) | (911) | (716) |
| Equity contribution from PG&E Corporation | 455 | 835 | 705 |

| | | | |
|---|---|---|---|
| Other | (93) | (30) | (13) |
| **Net cash provided by financing activities** | **110** | **1,194** | **1,468** |
| **Net change in cash and cash equivalents** | **376** | **12** | **4** |
| **Cash and cash equivalents at January 1** | **71** | **59** | **55** |
| **Cash and cash equivalents at December 31** | **$ 447** | **$ 71** | **$ 59** |



| | | | |
|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (781) | $ (717) | $ (675) |
| Income taxes, net | 162 | 244 | 77 |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Capital expenditures financed through accounts payable | $ 501 | $ 403 | $ 440 |
| Terminated capital leases | 23 | 18 | - |

See accompanying Notes to the Consolidated Financial Statements.



**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**
**(in millions)**

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2014** | **$ 258** | **$ 1,322** | **$ 6,514** | **$ 8,130** | **$ 5** | **$ 16,229** |
| Net income | - | - | - | 862 | - | 862 |
| Other comprehensive loss | - | - | - | - | (2) | (2) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (4) | - | - | (4) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **$ 258** | **$ 1,322** | **$ 7,215** | **$ 8,262** | **$ 3** | **$ 17,060** |
| Cumulative effect of change in accounting principle | - | - | - | 24 | - | 24 |
| Net income | - | - | - | 1,402 | - | 1,402 |
| Other comprehensive loss | - | - | - | - | (1) | (1) |
| Equity contribution | - | - | 835 | - | - | 835 |
| Common stock dividend | - | - | - | (911) | - | (911) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2016** | **$ 258** | **$ 1,322** | **$ 8,050** | **$ 8,763** | **$ 2** | **$ 18,395** |
| Net income | - | - | - | 1,691 | - | 1,691 |
| Other comprehensive income | - | - | - | - | 4 | 4 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Equity contribution | - | - | 455 | - | - | 455 |
| Common stock dividend | - | - | - | (784) | - | (784) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2017** | **$ 258** | **$ 1,322** | **$ 8,505** | **$ 9,656** | **$ 6** | **$ 19,747** |

See accompanying Notes to the Consolidated Financial Statements.



## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations and cash flows during the period in which such change occurred.

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44. The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. See "Northern California Wildfires" in Note 13 below.

### NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

**Regulation and Regulated Operations**

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover "revenue requirements" that have been authorized by the CPUC or the FERC based on the Utility's cost of providing service. The Utility also records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable. To the extent that portions of the Utility's operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.



**Revenue Recognition**

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred. The Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. These differences have no impact on net income.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled, net of revenues subject to refund.

**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

**Allowance for Doubtful Accounts Receivable**

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectable customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

**Inventories**

Inventories are carried at weighted-average cost and include natural gas stored underground as well as materials and supplies. Natural gas stored underground is recorded to inventory when injected and then expensed as the gas is withdrawn for distribution to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and expensed or capitalized to plant, as appropriate, when consumed or installed.

**Emission Allowances**

The Utility purchases GHG emission allowances to satisfy its compliance obligations. Associated costs are recorded as inventory and included in current assets - other and other noncurrent assets - other on the Consolidated Balance Sheets. Costs are carried at weighted-average and are recoverable through rates.



**Property, Plant, and Equipment**

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value. Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

| (in millions, except estimated useful lives) | Estimated Useful Lives (years) | Balance at December 31, 2017 | 2016 |
|---|---|---|---|
| Electricity generating facilities [1] | 5 to 120 | $ 11,843 | $ 11,308 |
| Electricity distribution facilities | 15 to 65 | 31,110 | 29,836 |
| Electricity transmission facilities | 15 to 75 | 12,180 | 11,412 |
| Natural gas distribution facilities | 5 to 60 | 12,312 | 11,362 |
| Natural gas transmission and storage facilities | 5 to 62 | 7,329 | 6,491 |
| Construction work in progress | | 2,471 | 2,184 |
| **Total property, plant, and equipment** | | **77,245** | **72,593** |
| Accumulated depreciation | | (23,456) | (22,012) |
| **Net property, plant, and equipment** | | **$ 53,789** | **$ 50,581** |

[1] Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as used based on the amount of energy output. (See Note 13 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.83% in 2017, 3.73% in 2016, and 3.80% in 2015. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $38 million and $89 million during 2017, $51 million and $112 million during 2016, and $48 million and $107 million during 2015.

**Asset Retirement Obligations**

The following table summarizes the changes in ARO liability during 2017 and 2016, including nuclear decommissioning obligations:

| (in millions) | 2017 | 2016 |
|---|---|---|
| ARO liability at beginning of year | $ 4,684 | $ 3,643 |
| Revision in estimated cash flows | 128 | 968 |
| Accretion | 207 | 194 |
| Liabilities settled | (120) | (121) |
| **ARO liability at end of year** | **$ 4,899** | **$ 4,684** |

The Utility has not recorded a liability related to certain ARO's for assets that are expected to operate in perpetuity. As the Utility cannot estimate a settlement date or range of potential settlement dates for these assets, reasonable estimates of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities associated with substations, photovoltaic facilities, and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration of land to specified conditions under certain agreements.

*Nuclear Decommissioning Obligation*

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. On May 25, 2017, the CPUC issued a final decision in the 2015 NDCTP adopting a nuclear decommissioning cost estimate of $1.1 billion for Humboldt Bay, corresponding to the Utility's request, and $2.4 billion for Diablo Canyon, representing 64% of the Utility's request of $3.8 billion. On an aggregate basis, the final decision adopted a $3.5 billion total nuclear decommissioning cost estimate, compared to $4.8 billion requested by the Utility. Compared to the Utility's estimated cost to decommission Diablo Canyon, the final decision adopts assumptions which lower costs for large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility can seek recovery of these costs in the 2018 NDCTP. The CPUC's final decision resulted in a $66 million reduction to the ARO on the Consolidated Balance Sheets related to the assumed length of the wet cooling period of spent nuclear fuel after plant shut down. PG&E Corporation and the Utility recorded an increase of $92 million to the ARO recognized on the Consolidated Balance Sheets, to align the decommissioning cost estimate with the CPUC's final decision on the Utility's application to retire Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $3.5 billion at both December 31, 2017 and 2016. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $4.1 billion at December 31, 2017 (or $7 billion in future dollars). These estimates are based on the 2017 decommissioning cost studies, prepared in accordance with CPUC requirements.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. (See "Enforcement and Litigation Matters" in Note 13 below.)

**Nuclear Decommissioning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2017, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2017, it did not consolidate any of them.

**Other Accounting Policies**

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies and Commitments" in Note 13 herein.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2017 consisted of the following:

| **(in millions, net of income tax)** | **Pension Benefits** | **Other Benefits** | **Total** |
|---|---|---|---|
| Beginning balance | **$ (25)** | **$ 16** | **$ (9)** |
| **Other comprehensive income before reclassifications:** | | | |
| Unrecognized prior service cost (net of taxes of $4 and $0, respectively) | (6) | - | (6) |
| Unrecognized net actuarial loss (net of taxes of $229 and $97, respectively) | 333 | 141 | 474 |
| Regulatory account transfer (net of taxes of $225 and $97, respectively) | (327) | (141) | (468) |
| **Amounts reclassified from other comprehensive income:** | | | |
| Amortization of prior service cost (net of taxes of $3 and $6, respectively) (1) | (4) | 9 | 5 |
| Amortization of net actuarial loss (net of taxes of $9 and $2, respectively) (1) | 13 | 2 | 15 |
| Regulatory account transfer (net of taxes of $6 and $8, respectively) (1) | (9) | (10) | (19) |
| **Net current period other comprehensive loss** | **-** | **1** | **1** |
| Ending balance | **$ (25)** | **$ 17** | **$ (8)** |

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2016 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| Beginning balance | $ (23) | $ 16 | $ (7) |
| **Other comprehensive income before reclassifications:** | | | |
| Unrecognized prior service cost (net of taxes of $37 and $15, respectively) | 54 | (21) | 33 |
| Unrecognized net actuarial loss (net of taxes of $45 and $15, respectively) | (64) | 21 | (43) |
| Regulatory account transfer (net of taxes of $5 and $0, respectively) | 7 | - | 7 |
| **Amounts reclassified from other comprehensive income:** | | | |
| Amortization of prior service cost (net of taxes of $3 and $6, respectively) (1) | 5 | 9 | 14 |
| Amortization of net actuarial loss (net of taxes of $10 and $2, respectively) (1) | 14 | 2 | 16 |
| Regulatory account transfer (net of taxes of $13 and $8, respectively) (1) | (18) | (11) | (29) |
| **Net current period other comprehensive loss** | **(2)** | **-** | **(2)** |
| **Ending balance** | **$ (25)** | **$ 16** | **$ (9)** |

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Accounting Standards Issued But Not Yet Adopted***

***Presentation of Net Periodic Pension Cost***

In March 2017, the FASB issued ASU 2017-07, *Compensation - Retirement Benefits (Topic 715)*, which amends the existing guidance relating to the presentation of net periodic pension cost and net periodic other post-retirement benefit costs. On a retrospective basis, the amendment requires an employer to separate the service cost component from the other components of net benefit cost and provides explicit guidance on how to present the service cost component and other components in the income statement. In addition, on a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018. The FERC has allowed and the Utility has made a one-time election to adopt the new FASB guidance for regulatory filing purposes. In January 2018, the CPUC approved modifications to the Utility's calculation for pension-related revenue requirements to allow for capitalization of only the service cost component determined by a plan's actuaries. The change in capitalization of retirement benefits will not have a material impact on PG&E Corporation's and the Utility's Consolidated Financial Statements.

***Recognition of Lease Assets and Liabilities***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which amends the existing guidance relating to the definition of a lease, recognition of lease assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. In November, 2017, the FASB tentatively decided to amend the new leasing guidance such that entities may elect not to restate their comparative periods in the period of adoption. Under the new standard, all lessees must recognize an asset and liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019, with early adoption permitted. PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility expect this standard to increase lease assets and lease liabilities on the Consolidated Balance Sheets and do not expect the guidance will have a material impact on the Consolidated Statements of Income, Statements of Cash Flows and lease disclosures.

***Recognition and Measurement of Financial Assets and Financial Liabilities***

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*, which amends the existing guidance relating to the recognition, measurement, presentation, and disclosure of financial instruments. The amendments require equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. The majority of PG&E Corporation's and the Utility's investments are held in the nuclear decommissioning trusts. These investments are classified as "available-for-sale" and gains or losses are refundable, or recoverable, from customers through rates. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018 and will not have a material impact on the Consolidated Financial Statements and related disclosures.

***Revenue Recognition Standard***

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which amends existing revenue recognition guidance. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability across entities, industries, jurisdictions, and capital markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018. This standard will be adopted for related disclosures in the first quarter of 2018 and will not have a material impact on the Consolidated Financial Statements. Upon adoption of ASU 2014-09, the Utility plans to disclose revenues from contracts with customers separately from regulatory balancing account revenue and disaggregate customer contract revenue by customer class.

## NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

### Regulatory Assets

*Current Regulatory Assets*

At December 31, 2017 and 2016, the Utility had current regulatory assets of $615 million and $423 million, respectively. At December 31, 2017 and 2016, the current regulatory assets included $426 million and $223 million, respectively, of costs related to CEMA fire prevention and vegetation management. Current regulatory assets are included within the current assets in the Consolidated Balance Sheets.



*Long-Term Regulatory Assets*

Long-term regulatory assets are comprised of the following:

| (in millions) | Balance at December 31, 2017 | 2016 | Recovery Period |
|---|---|---|---|
| Pension benefits [1] | $ 1,954 | $ 2,429 | Indefinitely [3] |
| Deferred income taxes [1][4] | - | 3,859 | |
| Utility retained generation [2] | 319 | 364 | 9 years |
| Environmental compliance costs [1] | 837 | 778 | 32 years |
| Price risk management [1] | 65 | 92 | 10 years |
| Unamortized loss, net of gain, on reacquired debt [1] | 79 | 76 | 25 years |
| Other | 539 | 353 | Various |
| **Total long-term regulatory assets** | **$ 3,793** | **$ 7,951** | |

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recognized in accordance with GAAP.

(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.

(3) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the Utility expects to continuously recover pension benefits.

(4) The change in the balance from a regulatory asset as of December 31, 2016 to a regulatory liability as of December 31, 2017 reflects the impact of changes in net deferred tax liabilities associated with a lower federal income tax rate as a result of the Tax Act. (See "Regulatory Liabilities" below and Note 8.)

At December 31, 2017 and 2016, other long-term regulatory assets included $274 million and $70 million, respectively, of costs related to CEMA events from 2014 through 2017 that the Utility believes are recoverable based on historical experience in recovering costs for these types of events.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, and unamortized loss, net of gain, on reacquired debt.

**Regulatory Liabilities**

*Long-Term Regulatory Liabilities*

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Balance at December 31, 2017 | 2016 |
|---|---|---|
| Cost of removal obligations [1] | $ 5,547 | $ 5,060 |
| Deferred income taxes [2] | 1,021 | - |
| Recoveries in excess of AROs [3] | 624 | 626 |
| Public purpose programs [4] | 590 | 567 |
| Other | 897 | 552 |
| **Total long-term regulatory liabilities** | **$ 8,679** | **$ 6,805** |

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.

(2) Represents the net of amounts owed to customers for deferred taxes collected at higher rates before the Tax Act and amounts owed to the Utility for reversal of deferred taxes subject to flow-through treatment. (See Note 8 below.)

(3) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 10 below.)

(4) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.



**Regulatory Balancing Accounts**

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets - regulatory assets or noncurrent liabilities - regulatory liabilities, respectively, in the Consolidated Balance Sheets. These differences do not have an impact on net income. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

| | Receivable | |
|---|---|---|
| | **Balance at December 31,** | |
| **(in millions)** | **2017** | **2016** |
| Electric distribution | $ - | $ 132 |
| Electric transmission | 139 | 244 |
| Utility generation | - | 48 |
| Gas distribution and transmission | 486 | 541 |
| Energy procurement | 71 | 132 |
| Public purpose programs | 103 | 106 |
| Other | 423 | 297 |
| **Total regulatory balancing accounts receivable** | **$ 1,222** | **$ 1,500** |

| | Payable | |
|---|---|---|
| | **Balance at December 31,** | |
| **(in millions)** | **2017** | **2016** |
| Electric distribution | $ 72 | $ - |
| Electric transmission | 120 | 99 |
| Utility generation | 14 | - |
| Gas distribution and transmission | - | 48 |
| Energy procurement | 149 | 13 |
| Public purpose programs | 452 | 264 |
| Other | 313 | 221 |
| **Total regulatory balancing accounts payable** | **$ 1,120** | **$ 645** |

The electric distribution and utility generation accounts track the collection of revenue requirements approved in the GRC. The electric transmission accounts track recovery of costs related to the transmission of electricity. The gas distribution and transmission accounts track the collection of revenue requirements approved in the GRC and the GT&S rate case. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency.

## NOTE 4: DEBT

### Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

| (in millions) | | December 31, 2017 | 2016 |
|---|---|---|---|
| **PG&E Corporation** | | | |
| Senior notes: | | | |
| Maturity | Interest Rates | | |
| 2019 | 2.40% | $ 350 | $ 350 |
| Unamortized discount, net of premium and debt issuance costs | | - | (2) |
| **Total PG&E Corporation long-term debt** | | **350** | **348** |
| **Utility** | | | |
| Senior notes: | | | |
| Maturity | Interest Rates | | |
| 2017 | 5.63% | - | 700 |
| 2018 | 8.25% | 400 | 800 |
| 2020 | 3.50% | 800 | 800 |
| 2021 | 3.25% to 4.25% | 550 | 550 |
| 2022 | 2.45% | 400 | 400 |
| 2023 through 2047 | 2.95% to 6.35% | 14,975 | 12,375 |
| Less: current portion [1] | | (400) | (700) |
| Unamortized discount, net of premium and debt issuance costs | | (185) | (161) |
| **Total senior notes, net of current portion** | | **16,540** | **14,764** |
| Pollution control bonds: | | | |
| Maturity | Interest Rates | | |
| Series 2004 A-D due 2023 [2] | 4.75% | - | 345 |
| Series 2008 F and 2010 E, due 2026 [3] | 1.75% | 100 | - |
| Series 2008 G, due 2018 [4] | 1.05% | 45 | - |
| Series 2009 A-B, due 2026 [5] | 1.78% | 149 | 149 |
| Series 1996 C, E, F, 1997 B due 2026 [6] | variable rate [7] | 614 | 614 |
| Less: current portion | | (45) | - |
| **Total pollution control bonds** | | **863** | **1,108** |
| **Total Utility long-term debt, net of current portion** | | **17,403** | **15,872** |
| **Total consolidated long-term debt, net of current portion** | | **$ 17,753** | **$ 16,220** |

(1) On January 19, 2018, the Utility sent a notice of redemption to redeem all $400 million aggregate principal amount of the 8.25% senior notes due October 15, 2018 on February 18, 2018. On January 31, 2018, the Utility deposited with the trustee funds sufficient to effect the early redemption of these bonds and satisfy and discharge its remaining obligation of $400 million.

(2) In June 2017, the Utility repurchased and retired $345 million principal amount of Pollution Control Bonds series 2004 A-D.

(3) Pollution Control Bonds series 2008F and 2010E were remarketed and issued in June 2017. Although the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 30, 2022.

(4) Pollution Control Bonds series 2008G were remarketed and issued in June 2017 and mature on December 1, 2018.

(5) Each series of these bonds is supported by a separate direct-pay letter of credit. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

(6) Each series of these bonds is supported by a separate letter of credit. In December 2015, the letters of credit were extended to December 1, 2020. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(7) At December 31, 2017, the interest rate on these bonds ranged from 1.45% - 1.70%.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sales agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. Except for components that may have been abandoned in place or disposed of as scrap or that are permanently non-operational, the Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

**Repayment Schedule**

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2017 are reflected in the table below:

| (in millions, except interest rates) | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest rate | - | 2.40% | - | - | - | - | 2.40% |
| Fixed rate obligations | $ - | $ 350 | $ - | $ - | $ - | $ - | $ 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | 7.52% | - | 3.50% | 3.80% | 2.31% | 4.68% | 4.61% |
| Fixed rate obligations | $ 445 | $ - | $ 800 | $ 550 | $ 500 (2) | $ 14,975 | $ 17,270 |
| Variable interest rate as of December 31, 2017 | - | 1.78% | 1.59% | - | - | - | 1.63% |
| Variable rate obligations (1) | $ - | $ 149 | $ 614 | $ - | $ - | $ - | $ 763 |
| **Total consolidated debt** | **$ 445** | **$ 499** | **$ 1,414** | **$ 550** | **$ 500** | **$ 14,975** | **$ 18,383** |

(1) The bonds due in 2026 are backed by separate letters of credit that expire June 5, 2019, or December 1, 2020.

(2) Pollution Control Bonds series 2008F and 2010E were remarketed and issued in June 2017. Although the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 30, 2022.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at December 31, 2017:

| (in millions) | Termination Date | Credit Facility Limit | Letters of Credit Outstanding | Commercial Paper Outstanding | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2022 | $ 300 (1) | $ - | $ 132 | $ 168 |
| Utility | April 2022 | 3,000 (2) | 49 | 50 | 2,901 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 49** | **$ 182** | **$ 3,069** |

(1) Includes a $50 million lender commitment to the letter of credit sublimit and a $100 million commitment for swingline loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.

(2) Includes a $500 million lender commitment to the letter of credit sublimit and a $75 million commitment for swingline loans.

For the year ended December 31, 2017, PG&E Corporation's average outstanding commercial paper balance was $81 million and the maximum outstanding balance during the year was $161 million. For 2017, the Utility's average outstanding commercial paper balance was $469 million and the maximum outstanding balance during the year was $1.1 billion. There were no bank borrowings for PG&E Corporation or the Utility in 2017.

***Revolving Credit Facilities***

In May 2017, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes. Borrowings under each credit agreement (other than swingline loans) will bear interest based on the borrower’s credit rating and on each borrower’s election of either (1) a London Interbank Offered Rate (“LIBOR”) plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent’s announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The borrower’s credit rating at the time of borrowing will determine the applicable rate within the following ranges. The applicable margin for LIBOR loans will range between 0.9% and 1.475% under PG&E Corporation’s credit agreement and between 0.8% and 1.275% under the Utility’s credit agreement. The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation’s credit agreement and between 0% and 0.275% under the Utility’s credit agreement. In addition, the facility fee under PG&E Corporation’s and the Utility’s credit agreements will range between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

PG&E Corporation’s and the Utility’s revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the respective revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation’s revolving credit facility agreement also requires that PG&E Corporation owns, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

***Commercial Paper Programs***

The borrowings from PG&E Corporation’s and the Utility’s commercial paper programs are used primarily to fund temporary financing needs. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation’s and the Utility’s other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. For 2017, the average yield on outstanding PG&E Corporation and Utility commercial paper was 1.29% and 1.11%, respectively.

***Other Short-term Borrowings***

In February 2017, the Utility’s $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid. Additionally, in February 2017, the Utility entered into a $250 million floating rate unsecured term loan maturing on February 22, 2018. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility’s outstanding commercial paper.

In November 2017, the Utility issued $500 million in unsecured floating rate senior notes that mature on November 28, 2018. The proceeds were used towards repayment of the $250 million unsecured floating rate senior notes due November 30, 2017 and the balance was used to support the Northern California wildfire response efforts.

**NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION**

PG&E Corporation had 514,755,845 shares of common stock outstanding at December 31, 2017. PG&E Corporation held all of the Utility’s outstanding common stock at December 31, 2017.

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate price of up to $275 million. During 2017, PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $28.4 million, net of commissions paid of $0.2 million. There were no issuances under the February 2017 EDA for the three months ended December 31, 2017. As of December 31, 2017, the remaining sales available under this agreement were $246.3 million.

In addition, during 2017, PG&E Corporation sold 7.4 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $366.4 million.

**Dividends**

Ordinarily, the Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio for each company, no amount of PG&E Corporation's retained earnings and $218 million of the Utility's retained earnings was subject to this restriction at December 31, 2017. Additionally, the Utility's net assets, and therefore its ability to pay dividends, are restricted by the CPUC-authorized capital structure, which requires the Utility to maintain, on average, at least 52% equity. Based on the calculation of this ratio, $14.3 billion of the Utility's net assets were restricted at December 31, 2017. Additionally, as a result of this requirement, the Utility's ability to pay dividends in the future could be impacted by future potential liabilities. On December 20, 2017, the Board of Directors of PG&E Corporation suspended quarterly cash dividends on PG&E Corporation's common stock, beginning with the fourth quarter of 2017 due to uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See "Northern California Wildfires" in Note 13 below.)

For the first quarter of 2017, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share quarterly. In May 2017, the Board of Directors of PG&E Corporation approved a new annual common stock cash dividend of $0.53 per share quarterly. In 2017, total dividends declared were $1.55 per share.

**Long-Term Incentive Plan**

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 14,327,157 shares were available for future awards at December 31, 2017.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2017, 2016, and 2015:

| **(in millions)** | **2017** | **2016** | **2015** |
|---|---|---|---|
| Restricted stock units | $ 40 | $ 53 | $ 47 |
| Performance shares | 45 | 55 | 46 |
| Total compensation expense (pre-tax) | **$ 85** | **$ 108** | **$ 93** |
| Total compensation expense (after-tax) | **$ 50** | **$ 64** | **$ 55** |

The amount of share-based compensation costs capitalized during 2017, 2016, and 2015 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

Restricted stock units generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2017, 2016, and 2015 was $66.95, $56.68, and $53.30, respectively. The total fair value of restricted stock units that vested during 2017, 2016, and 2015 was $57 million, $36 million, and $57 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2017, $33 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.46 years.

The following table summarizes restricted stock unit activity for 2017:

| | Number of Restricted Stock Units | | Weighted Average Grant-Date Fair Value |
|---|---|---|---|
| Nonvested at January 1 | 1,923,010 | $ | 51.26 |
| Granted | 658,395 | | 66.95 |
| Vested | (1,172,194) | | 48.44 |
| Forfeited | (29,976) | | 61.07 |
| Nonvested at December 31 | **1,379,235** | $ | 60.93 |

***Performance Shares***

Performance shares generally will vest three years after the grant date. Upon vesting, performance shares are settled in shares of common stock based on either PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period or, for a small number of awards, an internal PG&E Corporation metric. Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled.

Compensation expense attributable to performance share is generally recognized rateably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value of PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2017, 2016, and 2015 was $77.00, $53.61, and $68.27, respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2017, $46 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.42 years.

The following table summarizes activity for performance shares in 2017:

| | Number of Performance Shares | | Weighted Average Grant-Date Fair Value |
|---|---|---|---|
| Nonvested at January 1 | 1,838,855 | $ | 58.65 |
| Granted | 745,724 | | 77.00 |
| Vested | (81,501) | | 53.74 |
| Forfeited [(1)] | (755,050) | | 66.30 |
| Nonvested at December 31 | **1,748,028** | $ | 63.40 |

[(1)] Includes performance shares that expired with zero value as performance targets were not met.

**NOTE 6: PREFERRED STOCK**

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. At December 31, 2017 and December 31, 2016, the Utility's preferred stock outstanding included $145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $113 million of shares with interest rates between 4.36% and 5% that are redeemable between $25.75 and $27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

At December 31, 2017, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2017, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility determined to suspend quarterly cash dividends on the Utility's preferred stock, beginning with the three-month period ending January 31, 2018, due to uncertainty related to causes and potential liabilities associated with the October 2017 Northern California wildfires. See "Northern California Wildfires" in Note 13 below.)

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid $14 million of dividends on preferred stock in each of 2017, 2016, and 2015.

**NOTE 7: EARNINGS PER SHARE**

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2017, 2016, and 2015.

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2017** | **2016** | **2015** |
| **Income available for common shareholders** | $ 1,646 | $ 1,393 | $ 874 |
| **Weighted average common shares outstanding, basic** | 512 | 499 | 484 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | 1 | 2 | 3 |
| **Weighted average common share outstanding, diluted** | 513 | 501 | 487 |
| **Total earnings per common share, diluted** | **$ 3.21** | **$ 2.78** | **$ 1.79** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

**NOTE 8: INCOME TAXES**

PG&E Corporation and the Utility use the asset and liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance in the financial statements represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.



The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

| PG&E Corporation | Utility |
|---|---|

| (in millions) | Year Ended December 31, 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
|---|---|---|---|---|---|---|
| Current: | | | | | | |
| Federal | $ (10) | $ (105) | $ (89) | $ 61 | $ (105) | $ (88) |
| State | 48 | (70) | 11 | 50 | (66) | 6 |
| Deferred: | | | | | | |
| Federal | 481 | 218 | 131 | 326 | 229 | 136 |
| State | 6 | 16 | (76) | 4 | 16 | (69) |
| Tax credits | (14) | (4) | (4) | (14) | (4) | (4) |
| **Income tax provision (benefit)** | **$ 511** | **$ 55** | **$ (27)** | **$ 427** | **$ 70** | **$ (19)** |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| **(in millions)** | **2017** | **2016** | **2017** | **2016** |
| **Deferred income tax assets:** | | | | |
| Tax carryforwards | $ 830 | $ 1,851 | $ 736 | $ 1,596 |
| Compensation | 274 | 277 | 205 | 199 |
| Income tax regulatory liability [1] | 286 | - | 286 | - |
| Other [2] | 185 | 186 | 194 | 203 |
| **Total deferred income tax assets** | **$ 1,575** | **$ 2,314** | **$ 1,421** | **$ 1,998** |
| **Deferred income tax liabilities:** | | | | |
| Property related basis differences | 7,269 | 10,429 | 7,256 | 10,411 |
| Income tax regulatory asset [1] | - | 1,572 | - | 1,572 |
| Other [3] | 128 | 526 | 128 | 525 |
| **Total deferred income tax liabilities** | **$ 7,397** | **$ 12,527** | **$ 7,384** | **$ 12,508** |
| **Total net deferred income tax liabilities** | **$ 5,822** | **$ 10,213** | **$ 5,963** | **$ 10,510** |

(1) Represents the tax gross up portion of the deferred income tax for the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized for tax, including the impact of changes in net deferred taxes associated with a lower federal income tax rate as a result of the Tax Act. (For more information see Note 3 above and "Tax Cuts and Jobs Act of 2017" below.)

(2) Amounts include benefits, environmental reserve, and customer advances for construction.

(3) Amounts primarily relate to regulatory balancing accounts.

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) [1] | 1.5 | (2.5) | (4.9) | 1.6 | (2.2) | (4.8) |
| Effect of regulatory treatment of fixed asset differences [2] | (16.5) | (23.7) | (33.6) | (16.8) | (23.4) | (33.7) |
| Tax credits | (1.1) | (0.8) | (1.3) | (1.1) | (0.8) | (1.3) |
| Benefit of loss carryback | - | (1.1) | (1.5) | - | (1.1) | (1.5) |
| Non deductible penalties [3] | 0.4 | 0.8 | 4.3 | 0.4 | 0.8 | 4.3 |
| Tax Reform Adjustment [4] | 6.8 | - | - | 3.0 | - | - |
| Other, net [5] | (2.5) | (3.9) | (1.1) | (2.0) | (3.5) | (0.2) |
| **Effective tax rate** | **23.6 %** | **3.8 %** | **(3.1) %** | **20.1 %** | **4.8 %** | **(2.2) %** |

[(1)] Includes the effect of state flow-through ratemaking treatment. In 2016 and 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions. The 2017 amount reflects an agreement with the IRS on a 2013 audit related to generation repairs deductions.

[(2)] Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted 2016 and 2017. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.



[(3)] Primarily represents the effects of a non-tax deductible penalty associated with the Butte fire for 2017, non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for 2016 and the effects of the San Bruno Penalty Decision for 2015.

[(4)] Represents the required adjustment to deferred tax balances, due to the federal income tax rate being lowered from 35% to 21% beginning in 2018 as a result of the enactment of the Tax Act.

[(5)] These amounts primarily represent the impact of tax audit settlements.

***Unrecognized Tax Benefits***

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| **Balance at beginning of year** | $ 388 | $ 468 | $ 713 | $ 382 | $ 462 | $ 707 |
| Additions for tax position taken during a prior year | - | - | 40 | - | - | 40 |
| Reductions for tax position taken during a prior year | (71) | (77) | (349) | (71) | (77) | (349) |
| Additions for tax position taken during the current year | 48 | 56 | 64 | 48 | 56 | 64 |
| Settlements | (14) | (59) | - | (8) | (59) | - |
| Expiration of statute | (3) | - | - | (3) | - | - |
| **Balance at end of year** | **$ 349** | **$ 388** | **$ 468** | **$ 349** | **$ 382** | **$ 462** |

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2017 for PG&E Corporation and the Utility was $21 million.

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2017, it is reasonably possible that unrecognized tax benefits will decrease by approximately $20 million within the next 12 months.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2017, 2016, and 2015, these amounts were immaterial.

***Tax Cuts and Jobs Act of 2017***

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and eliminated bonus depreciation for utilities. The Tax Act required PG&E Corporation and the Utility to re-measure all existing deferred income tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility have made reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by the SEC in Staff Accounting Bulletin No. 118, for the re-measurement of deferred tax balances as of December 31, 2017.

During the three months and year ended December 31, 2017, PG&E Corporation, on a consolidated basis, recorded a one-time provisional tax expense of $147 million to reflect the transitional impacts of the Tax Act. Of this amount, $83 million is attributable to the re-measurement of PG&E Corporation's net deferred tax asset comprised primarily of net operating loss carry-forwards and compensation-related items. The remaining $64 million is related to the re-measurement of the Utility's deferred taxes not reflected in authorized revenue requirements, such as disallowed plant. The Utility also recorded a provisional $5.7 billion re-measurement of its deferred tax balances (related to flow-through and normalized timing differences for plant-related items) which was offset by a change from a net deferred income tax regulatory asset to a net regulatory liability. The deferred income tax regulatory liability will be refunded to customers over the regulatory lives of the related assets.

The final transition impacts of the Tax Act may differ from the above recorded amounts, possibly materially, due to, among other things, regulatory decisions from the CPUC that could differ from the Utility's determination of how the impacts of the Tax Act are allocated between customers and shareholders. In addition, while PG&E Corporation and the Utility were able to make reasonable estimates of the impact of the reduction in federal tax rate and the elimination of bonus depreciation due to the enactment of the Tax Act; changes in interpretations, guidance on legislative intent, and any changes in accounting standards for income taxes in response to the Tax Act could impact the recorded amounts. PG&E Corporation and the Utility will finalize and record any adjustments related to the Tax Act within the one year measurement period provided under Staff Accounting Bulletin No. 118.

***Tax Settlements***

PG&E Corporation's tax returns have been accepted through 2015 except for a few matters, the most significant of which relates to deductible repair costs for gas transmission and distribution lines of business. In February 2017, the Joint Committee of Taxation approved PG&E Corporation's settlement with the IRS related to deductible electric transmission and distribution repairs for the 2011 and 2012 tax years. The agreement provided that the methodology used in determining the deductible amount should be followed for all subsequent periods, absent any material change in facts. In November 2017, PG&E Corporation reached an agreement with the IRS on deductible generation repairs for the 2013 and 2014 tax years. The IRS may issue guidance in 2018 that clarifies which repair costs are deductible for the natural gas transmission and distribution lines of business.

Tax years after 2008 remain subject to examination by the state of California.

***2015 Gas Transmission and Storage Rate Case***

The final phase two decision reduced rate base by the full amount of the disallowed capital expenditures but did not remove the associated deferred taxes, which the Utility believes constitutes a normalization violation. In the final decision, the CPUC authorized the Utility to establish a Tax Normalization Memorandum Account to track relevant costs and clarified that it is the CPUC's intention that the Utility comply with normalization rules and avoid the potential adverse consequences of a normalization violation. The CPUC allowed the Utility to seek a ruling from the IRS and the Utility filed the ruling request with the IRS on April 10, 2017. On October 5, 2017, the IRS issued a private letter ruling indicating the final decision rate base reduction was inconsistent with the IRS tax normalization requirements. As a result of the IRS private letter ruling, the Utility filed an advice letter with the CPUC on December 11, 2017, requesting a rate base adjustment of $7 million, $28 million, $49 million, and $61 million, in 2015, 2016, 2017, and 2018, respectively.

***Carryforwards***

The following table describes PG&E Corporation's operating loss and tax credit carryforward balances:

| (in millions) | | December 31, 2017 | Expiration Year |
|---|---|---|---|
| **Federal:** | | | |
| Net operating loss carryforward | $ | 4,233 | 2031 - 2036 |
| Tax credit carryforward | | 103 | 2029 - 2036 |
| Charitable contribution loss carryforward | | 93 | 2019 - 2021 |
| | | | |
| **State:** | | | |
| Net operating loss carryforward | $ | - | N/A |
| Tax credit carryforward | | 13 | Various |
| Charitable contribution loss carryforward | | 24 | 2020 - 2021 |

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating losses, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2017 for these tax attributes.

## NOTE 9: DERIVATIVES

### Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs.

Derivatives are presented in the Utility's Consolidated Balance Sheets recorded at fair value and on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

### Volume of Derivative Activity

At December 31, 2017 and 2016, respectively, the volumes of the Utility's outstanding derivatives were as follows:

| | | Contract Volume | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **2017** | **2016** |
| Natural Gas[1] (MMBtus[2]) | Forwards and Swaps | 228,768,745 | 323,301,331 |
| | Options | 60,736,806 | 96,602,785 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 2,872,013 | 3,287,397 |
| | Congestion Revenue Rights[3] | 312,272,177 | 278,143,281 |

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

### Presentation of Derivative Instruments in the Financial Statements

At December 31, 2017, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets - other | $ 30 | $ (3) | $ 10 | $ 37 |
| Other noncurrent assets - other | 103 | (1) | - | 102 |
| Current liabilities - other | (47) | 3 | 13 | (31) |
| Noncurrent liabilities - other | (66) | 1 | 8 | (57) |
| **Total commodity risk** | **$ 20** | **$ -** | **$ 31** | **$ 51** |

At December 31, 2016, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets - other | $ 91 | $ (10) | $ 1 | **$ 82** |
| Other noncurrent assets - other | 149 | (9) | - | **140** |
| Current liabilities - other | (48) | 10 | - | **(38)** |
| Noncurrent liabilities - other | (101) | 9 | 3 | **(89)** |
| **Total commodity risk** | **$ 91** | **$ -** | **$ 4** | **$ 95** |

Gains and losses associated with price risk management activities were recorded as follows:

| | Commodity Risk | | |
|---|---|---|---|
| | For the year ended December 31, | | |
| **(in millions)** | **2017** | **2016** | **2015** |
| Unrealized gain/(loss) - regulatory assets and liabilities[1] | $ (71) | $ 64 | $ (6) |
| Realized loss - cost of electricity[2] | (27) | (53) | (14) |
| Realized loss - cost of natural gas[2] | (5) | (18) | (10) |
| **Total commodity risk** | **$ (103)** | **$ (7)** | **$ (30)** |

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
[2] These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2017, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| (in millions) | Balance at December 31, 2017 | | Balance at December 31, 2016 | |
|---|---|---|---|---|
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ | (1) | $ | (24) |
| Related derivatives in an asset position | | - | | 19 |
| Collateral posting in the normal course of business related to these derivatives | | - | | 4 |
| **Net position of derivative contracts/additional collateral posting requirements[1]** | **$** | **(1)** | **$** | **(1)** |

[1] This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

**NOTE 10: FAIR VALUE MEASUREMENTS**

PG&E Corporation and the Utility measure their cash equivalents, trust assets and price risk management instruments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 -** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 -** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 -** Unobservable inputs which are supported by little or no market activities.



The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2017 | | | | |
| (in millions) | Level 1 | Level 2 | Level 3 | Netting [1] | Total |
| **Assets:** | | | | | |
| Short-term investments | $ 385 | $ - | $ - | $ - | **$ 385** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 23 | - | - | - | **23** |
| Global equity securities | 1,967 | - | - | - | **1,967** |
| Fixed-income securities | 733 | 562 | - | - | **1,295** |
| Assets measured at NAV | - | - | - | - | **18** |
| **Total nuclear decommissioning trusts [2]** | **2,723** | **562** | **-** | **-** | **3,303** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | - | 3 | 129 | 6 | **138** |
| Gas | - | 1 | - | - | **1** |
| **Total price risk management instruments** | **-** | **4** | **129** | **6** | **139** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 72 | - | - | **72** |
| Life insurance contracts | - | 71 | - | - | **71** |
| **Total rabbi trusts** | **-** | **143** | **-** | **-** | **143** |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | - | - | - | **8** |
| Assets measured at NAV | - | - | - | - | **167** |
| **Total long-term disability trust** | **8** | **-** | **-** | **-** | **175** |
| **TOTAL ASSETS** | **$ 3,116** | **$ 709** | **$ 129** | **$ 6** | **$ 4,145** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 10 | $ 15 | $ 87 | $ (25) | **$ 87** |
| Gas | - | 1 | - | - | **1** |
| **TOTAL LIABILITIES** | **$ 10** | **$ 16** | **$ 87** | **$ (25)** | **$ 88** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $440 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2016 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Short-term investments | $ 105 | $ - | $ - | $ - | **$ 105** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 9 | - | - | - | **9** |
| Global equity securities | 1,724 | - | - | - | **1,724** |
| Fixed-income securities | 665 | 527 | - | - | **1,192** |
| Assets measured at NAV | - | - | - | - | **14** |
| **Total nuclear decommissioning trusts [2]** | **2,398** | **527** | **-** | **-** | **2,939** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 30 | 18 | 181 | (18) | **211** |
| Gas | - | 11 | - | - | **11** |
| **Total price risk management instruments** | **30** | **29** | **181** | **(18)** | **222** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 61 | - | - | **61** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **131** | **-** | **-** | **131** |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | - | - | - | **8** |
| Assets measured at NAV | - | - | - | - | **170** |
| **Total long-term disability trust** | **8** | **-** | **-** | **-** | **178** |
| **TOTAL ASSETS** | **$ 2,541** | **$ 687** | **$ 181** | **$ (18)** | **$ 3,575** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 9 | $ 12 | $ 126 | $ (21) | **$ 126** |
| Gas | - | 2 | - | (1) | **1** |
| **TOTAL LIABILITIES** | **$ 9** | **$ 14** | **$ 126** | **$ (22)** | **$ 127** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $333 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the years ended December 31, 2017 and 2016.

***Trust Assets***

*Assets Measured at Fair Value*

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1. Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of fixed-income securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

*Assets Measured at NAV Using Practical Expedient*

Investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter. Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded and over-the-counter options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Financial Officer, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

| (in millions) | Fair Value at At December 31, 2017 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [1] |
| Congestion revenue rights | $ 129 | $ 24 | Market approach | CRR auction prices | (16.03) - $ 11.99 |
| Power purchase agreements | $ - | $ 63 | Discounted cash flow | Forward prices | 18.81 - $ 38.80 |

1. (1) Represents price per megawatt-hour

| (in millions) | Fair Value at At December 31, 2016 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [1] |
| Congestion revenue rights | $ 181 | $ 35 | Market approach | CRR auction prices | (11.88) - $ 6.93 |
| Power purchase agreements | $ - | $ 91 | Discounted cash flow | Forward prices | 18.07 - $ 38.80 |

[1] Represents price per megawatt-hour

**Level 3 Reconciliation**

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2017 and 2016, respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2017** | **2016** |
| Asset (liability) balance as of January 1 | **$ 55** | **$ 89** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | (13) | (34) |
| **Asset (liability) balance as of December 31** | **$ 42** | **$ 55** |

[1] The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2017 and 2016, as they are short-term in nature or have interest rates that reset daily.
- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2017 and 2016.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| **(in millions)** | **Carrying Amount** | **Level 2 Fair Value** | **Carrying Amount** | **Level 2 Fair Value** |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 350 | $ 350 | $ 348 | $ 352 |
| Utility | 17,090 | 19,128 | 15,813 | 17,790 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| (in millions) | | Amortized Cost | | Total Unrealized Gains | | Total Unrealized Losses | | Total Fair Value |
|---|---|---|---|---|---|---|---|---|
| **As of December 31, 2017** | | | | | | | | |
| Nuclear decommissioning trusts | | | | | | | | |
| Short-term investments | $ | 23 | $ | - | $ | - | $ | 23 |
| Global equity securities | | 524 | | 1,463 | | (2) | | 1,985 |
| Fixed-income securities | | 1,252 | | 51 | | (8) | | 1,295 |
| **Total** (1) | **$** | **1,799** | **$** | **1,514** | **$** | **(10)** | **$** | **3,303** |
| **As of December 31, 2016** | | | | | | | | |
| Nuclear decommissioning trusts | | | | | | | | |
| Short-term investments | $ | 9 | $ | - | $ | - | $ | 9 |
| Global equity securities | | 584 | | 1,157 | | (3) | | 1,738 |
| Fixed-income securities | | 1,156 | | 48 | | (12) | | 1,192 |
| **Total** (1) | **$** | **1,749** | **$** | **1,205** | **$** | **(15)** | **$** | **2,939** |

(1) Represents amounts before deducting $440 million and $333 million at December 31, 2017 and 2016, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

| (in millions) | | As of December 31, 2017 |
|---|---|---|
| Less than 1 year | $ | 41 |
| 1-5 years | | 414 |
| 5-10 years | | 352 |
| More than 10 years | | 488 |
| **Total maturities of fixed-income securities** | **$** | **1,295** |

The following table provides a summary of activity for the fixed-income and equity securities:

| (in millions) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning investments | $ | 1,291 | $ | 1,295 | $ | 1,268 |
| Gross realized gains on securities held as available-for-sale | | 53 | | 18 | | 55 |
| Gross realized losses on securities held as available-for-sale | | (11) | | (26) | | (37) |

**NOTE 11: EMPLOYEE BENEFIT PLANS**

**Pension Plan and Postretirement Benefits Other than Pensions ("PBOP")**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans is zero.

PG&E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utility use a fiscal year-end measurement date for all plans.

**Change in Plan Assets, Benefit Obligations, and Funded Status**

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2017 and 2016:

***Pension Plan***

| (in millions) | 2017 | 2016 |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 14,729** | **$ 13,745** |
| Actual return on plan assets | 2,380 | 1,358 |
| Company contributions | 335 | 334 |
| Benefits and expenses paid | (792) | (708) |
| **Fair value of plan assets at end of year** | **$ 16,652** | **$ 14,729** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 17,305** | **$ 16,299** |
| Service cost for benefits earned | 472 | 453 |
| Interest cost | 714 | 715 |
| Actuarial (gain) loss | 1,048 | 637 |
| Plan amendments | 10 | (91) |
| Benefits and expenses paid | (792) | (708) |
| **Benefit obligation at end of year** [(1)] | **$ 18,757** | **$ 17,305** |
| | | |
| **Funded Status:** | | |
| Current liability | $ (7) | $ (7) |
| Noncurrent liability | (2,098) | (2,569) |
| **Net liability at end of year** | **$ (2,105)** | **$ (2,576)** |

[(1)] PG&E Corporation's accumulated benefit obligation was $16.8 billion and $15.6 billion at December 31, 2017 and 2016, respectively.

*Postretirement Benefits Other than Pensions*

| (in millions) | | 2017 | | 2016 |
|---|---|---|---|---|
| **Change in plan assets:** | | | | |
| **Fair value of plan assets at beginning of year** | **$** | **2,173** | **$** | **2,035** |
| Actual return on plan assets | | 298 | | 167 |
| Company contributions | | 33 | | 52 |
| Plan participant contribution | | 87 | | 85 |
| Benefits and expenses paid | | (171) | | (166) |
| **Fair value of plan assets at end of year** | **$** | **2,420** | **$** | **2,173** |
| | | | | |
| **Change in benefit obligation:** | | | | |
| **Benefit obligation at beginning of year** | **$** | **1,877** | **$** | **1,766** |
| Service cost for benefits earned | | 59 | | 52 |
| Interest cost | | 77 | | 76 |
| Actuarial (gain) loss | | (49) | | 11 |
| Plan amendments | | - | | 37 |
| Benefits and expenses paid | | (157) | | (153) |
| Federal subsidy on benefits paid | | 3 | | 3 |
| Plan participant contributions | | 87 | | 85 |
| **Benefit obligation at end of year** | **$** | **1,897** | **$** | **1,877** |
| | | | | |
| Funded Status: [(1)] | | | | |
| Noncurrent asset | $ | 553 | $ | 368 |
| Noncurrent liability | | (30) | | (72) |
| **Net asset at end of year** | **$** | **523** | **$** | **296** |

[(1)] At December 31, 2017 and 2016, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

***Pension Plan***

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Service cost | $ 472 | $ 453 | $ 479 |
| Interest cost | 714 | 715 | 673 |
| Expected return on plan assets | (770) | (828) | (873) |
| Amortization of prior service cost | (7) | 8 | 15 |
| Amortization of net actuarial loss | 22 | 24 | 10 |
| **Net periodic benefit cost** | **431** | **372** | **304** |
| Less: transfer to regulatory account [(1)] | (92) | (34) | 34 |
| **Total expense recognized** | **$ 339** | **$ 338** | **$ 338** |

[(1)] The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

***Postretirement Benefits Other than Pensions***

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Service cost | $ 59 | $ 52 | $ 55 |
| Interest cost | 77 | 76 | 71 |
| Expected return on plan assets | (97) | (107) | (112) |
| Amortization of prior service cost | 15 | 15 | 19 |
| Amortization of net actuarial loss | 4 | 4 | 4 |
| **Net periodic benefit cost** | **$ 58** | **$ 40** | **$ 37** |

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record unrecognized prior service costs and unrecognized gains and losses related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax. In addition, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension benefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts that would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2018 are as follows:

| (in millions) | Pension Plan | PBOP Plans |
|---|---|---|
| Unrecognized prior service cost | $ (6) | $ 14 |
| Unrecognized net loss | 5 | (5) |
| **Total** | **$ (1)** | **$ 9** |

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

**Valuation Assumptions**

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | December 31, | | | December 31, | | |
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| **Discount rate** | 3.64 % | 4.11 % | 4.37 % | 3.60- 3.67 % | 4.05 - 4.19 % | 4.27 - 4.48 % |
| **Rate of future compensation increases** | 3.90 % | 4.00 % | 4.00 % | - | - | - |
| **Expected return on plan assets** | 6.20 % | 5.30 % | 6.10 % | 3.30 - 7.10 % | 2.80 - 6.00 % | 3.20 - 6.60 % |

The assumed health care cost trend rate as of December 31, 2017 was 6.8%, decreasing gradually to an ultimate trend rate in 2025 and beyond of approximately 4.5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| (in millions) | One-Percentage-Point Increase | One-Percentage-Point Decrease |
|---|---|---|
| Effect on postretirement benefit obligation | $ 128 | $ (129) |
| Effect on service and interest cost | 9 | (10) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.2% compares to a ten-year actual return of 7.8%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 623 Aa-grade non-callable bonds at December 31, 2017. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

**Investment Policies and Strategies**

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs in financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts' asset allocations are meant to manage volatility, reduce costs, and diversify its holdings. Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts' fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility, PG&E Corporation's and the Utility's trusts hold significant allocations in long maturity fixed-income investments. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, global REITS, and global listed infrastructure equities. Absolute return investments include hedge fund portfolios.

Derivative instruments such as equity index futures are used to meet target equity exposure. Derivative instruments, such as equity index futures and U.S. treasury futures, are also used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are used to hedge a portion of the non U.S. dollar exposure of global equity investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | **2018** | **2017** | **2016** | **2018** | **2017** | **2016** |
| Global equity | 29 % | 27 % | 25 % | 33 % | 32 % | 32 % |
| Absolute return | 5 % | 5 % | 5 % | 3 % | 3 % | 3 % |
| Real assets | 8 % | 10 % | 10 % | 6 % | 7 % | 7 % |
| Fixed income | 58 % | 58 % | 60 % | 58 % | 58 % | 58 % |
| **Total** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** |

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

**Fair Value Measurements**

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2017 and 2016.

| | Fair Value Measurements At December 31, 2017 | | | | 2016 | | | |
|---|---|---|---|---|---|---|---|---|
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Plan:** | | | | | | | | |
| Short-term investments | $ 287 | $ 424 | $ - | **$ 711** | $ 364 | $ 369 | $ - | **$ 733** |
| Global equity | 1,292 | - | - | **1,292** | 996 | - | - | **996** |
| Real assets | 499 | - | - | **499** | 610 | - | - | **610** |
| Fixed-income | 1,916 | 5,520 | 4 | **7,440** | 1,754 | 4,774 | 5 | **6,533** |
| Assets measured at NAV | - | - | - | **6,818** | - | - | - | **5,950** |
| **Total** | **$ 3,994** | **$ 5,944** | **$ 4** | **$ 16,760** | **$ 3,724** | **$ 5,143** | **$ 5** | **$ 14,822** |
| **PBOP Plans:** | | | | | | | | |
| Short-term investments | $ 31 | $ - | $ - | **$ 31** | $ 33 | $ - | $ - | **$ 33** |
| Global equity | 141 | - | - | **141** | 115 | - | - | **115** |
| Real assets | 55 | - | - | **55** | 70 | - | - | **70** |
| Fixed-income | 163 | 757 | - | **920** | 150 | 656 | - | **806** |
| Assets measured at NAV | - | - | - | **1,281** | - | - | - | **1,153** |
| **Total** | **$ 390** | **$ 757** | **$ -** | **$ 2,428** | **$ 368** | **$ 656** | **$ -** | **$ 2,177** |
| **Total plan assets at fair value** | | | | **$ 19,188** | | | | **$ 16,999** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $116 million and $97 million at December 31, 2017 and 2016, respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a NAV per share can be redeemed quarterly with a notice not to exceed 90 days.

***Short-Term Investments***

Short-term investments consist primarily of commingled funds across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

***Global Equity***

The global equity category includes investments in common stock and equity-index futures. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets.

***Real Assets***

The real asset category includes portfolios of commodity futures, global REITS and global listed infrastructure equities. The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets.

***Fixed-Income***

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

***Assets Measured at NAV Using Practical Expedient***

Investments in the trusts that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities, asset-backed securities, and private real estate funds. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

**Transfers Between Levels**

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No material transfers between levels occurred in the years ended December 31, 2017 and 2016.

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for the pension plan that have been classified as Level 3 for the years ended December 31, 2017 and 2016:

| **(in millions)**<br>**For the year ended December 31, 2017** | **Fixed-Income** |
|---|---|
| Balance at beginning of year | $ 5 |
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | (1) |
| Relating to assets sold during the period | - |
| Purchases, issuances, sales, and settlements: | |
| Purchases | 3 |
| Settlements | (3) |
| **Balance at end of year** | **$ 4** |

| **(in millions)**<br>**For the year ended December 31, 2016** | **Fixed-Income** |
|---|---|
| Balance at beginning of year | $ 3 |
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | 3 |
| Relating to assets sold during the period | - |
| Purchases, issuances, sales, and settlements: | |
| Purchases | - |
| Settlements | (1) |
| **Balance at end of year** | **$ 5** |

There were no material transfers out of Level 3 in 2017 and 2016.

**Cash Flow Information**

***Employer Contributions***

PG&E Corporation and the Utility contributed $335 million to the pension benefit plans and $33 million to the other benefit plans in 2017. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2017. The Utility's pension benefits met all the funding requirements under the Employee Retirement Income Security Act. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $24 million to the pension plan and other postretirement benefit plans, respectively, for 2018.

***Benefits Payments and Receipts***

As of December 31, 2017, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

| (in millions) | Pension Plan | PBOP Plans | Federal Subsidy |
|---|---|---|---|
| 2018 | $ 712 | $ 83 | $ (8) |
| 2019 | 811 | 87 | (9) |
| 2020 | 850 | 91 | (9) |
| 2021 | 886 | 95 | (10) |
| 2022 | 920 | 100 | (3) |
| Thereafter in the succeeding five years | $ 5,002 | $ 508 | $ (15) |

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

**Retirement Savings Plan**

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were $103 million, $97 million, and $89 million in 2017, 2016, and 2015, respectively. There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

**NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS**

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions) | 2017 | 2016 | 2015 |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 8 | $ 7 | $ 6 |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 65 | $ 74 | $ 53 |
| Utility employee benefit due to PG&E Corporation | 73 | 91 | 82 |

At December 31, 2017 and 2016, the Utility had receivables of $20 million and $18 million, respectively, from PG&E Corporation included in accounts receivable - other and other noncurrent assets - other on the Utility's Consolidated Balance Sheets, and payables of $22 million and $22 million, respectively, to PG&E Corporation included in accounts payable - other on the Utility's Consolidated Balance Sheets.

**NOTE 13: CONTINGENCIES AND COMMITMENTS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows may be materially affected by the outcome of the following matters.

**Enforcement and Litigation Matters**

***Northern California Wildfires***

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City. According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The Utility incurred $219 million in costs for service restoration and repair to the Utility's facilities (including $97 million in capital expenditures) through December 31, 2017 in connection with these fires. While the Utility believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs.

The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. The CPUC's SED also is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. (For example, on February 3, 2018, it was reported that investigators with the Santa Rosa Fire Department had completed their investigation of two small fires that reportedly destroyed two homes and damaged one outbuilding and had concluded that the Utility's facilities, along with high wind and other factors, contributed to those fires.) It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

As of January 31, 2018, the Utility had submitted 22 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire has identified a site as potentially involving the Utility's facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary, and does not reflect a determination of the causes of the fires. The investigations into the fires are ongoing.

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost

recovery even if a court decision were to determine that the doctrine of inverse condemnation applies. In addition to such claims for property damage, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.



Given the preliminary stages of investigations and the uncertainty as to the causes of the fires, PG&E Corporation and the Utility do not believe a loss is probable at this time. However, it is reasonably possible that facts could emerge through the course of the various investigations that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in an accrued liability in the future, the amount of which could be material. PG&E Corporation and the Utility currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur given the preliminary stages of the investigations and the uncertainty regarding the extent and magnitude of potential damages. On January 31, 2018, the California Department of Insurance issued a press release announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion estimated in respect of the wildfires that occurred in October 2017, depending on the extent of the damage in connection with such fire or fires. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

As of January 31, 2018, PG&E Corporation and the Utility are aware of 111 lawsuits, six of which seek to be certified as class actions, that have been filed against PG&E Corporation and the Utility in the Sonoma, Napa and San Francisco Counties Superior Courts. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, insurance carriers who have made payments to their insureds for property damage arising out of the fires have filed three subrogation complaints in the San Francisco County Superior Court. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. On October 31, 2017, a group of plaintiffs submitted a petition for coordination to the Chair of the Judicial Council of California and requested coordination of the litigation in the San Francisco Superior Court. On November 9, 2017, PG&E Corporation and the Utility submitted a petition for coordination to the Chair of the Judicial Council of California, and requested separate coordination in the counties in which the fires occurred. On January 4, 2018, the coordination motion judge of the San Francisco Superior Court entered an order granting coordination of the litigation in connection with the Northern California wildfires and recommending that the coordinated proceeding take place in the San Francisco Superior Court. On January 12, 2018, the Judicial Council of California accepted the coordination motion judge's recommendation and assigned the coordinated proceeding to San Francisco. The first case management conference is scheduled for February 27, 2018. In addition, two derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively. The first lawsuit is filed against the members of the Board of Directors and certain officers of PG&E Corporation. PG&E Corporation

is identified as a nominal defendant in that action. The second lawsuit is filed against the members of the Board of Directors, certain former members of the Board of Directors, and certain officers of both PG&E Corporation and the Utility. PG&E Corporation and the Utility are identified as nominal defendants in that action. Motions to consolidate the two lawsuits, appoint lead plaintiffs' counsel, and enter a case schedule are currently pending.

PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $800 million. If the Utility were to be found liable for one or more fires, the Utility's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires. Following the Northern California wildfires, PG&E Corporation reinstated its liability insurance in the amount of approximately $630 million for any potential future event.



In addition, it could take a number of years before the Utility's final liability is known and the Utility could apply for cost recovery. The Utility may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. Further, SB 819, introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities from recovering costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the utility did not reasonably construct, maintain, manage, control, or operate the facilities. PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

***Litigation and Regulatory Citations in Connection with the Butte Fire***

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a gray pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

*Third-Party Claims*

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2017, 77 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,770 individual plaintiffs representing approximately 2,030 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. As of December 31, 2017, several plaintiffs have dismissed the Utility's two vegetation management contractors. The number of individual complaints and plaintiffs may still increase in the future, because the statute of limitations for property damages in connection with the Butte fire has not yet expired. (The statute of limitations for personal injury in connection with the Butte fire has expired.) The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint with the Superior Court of the State of California, County of Calaveras, seeking to recover $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Tree's, Inc., one of the Utility's vegetation contractors. The Utility and Cal Fire are currently engaged in a mediation process.

Further, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million. This claim would include costs that the County of Calaveras incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire.

On April 28, 2017, the Utility moved for summary adjudication on plaintiffs' claims for punitive damages. On August 10, 2017, the Court denied the Utility's motion on the grounds that plaintiffs might be able to show conscious disregard for public safety based on the fact that the Utility relied on contractors to fulfill their contractual obligation to hire and train qualified employees. On August 16, 2017, the Utility filed a writ with the Court of Appeals challenging what the Utility believes is a novel theory of punitive damages liability. The Court of Appeals accepted the writ on September 15, 2017 and ordered the trial court and plaintiffs to show cause why the relief requested by the Utility should not be granted. Briefing on the writ was completed as of January 2, 2018. The Utility is seeking expedited review of the motion.



On June 22, 2017, the Superior Court for the County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inverse condemnation applies to the Utility with respect to the Butte fire. The court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding, others could file lawsuits and make similar claims. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases. The motion is set for hearing on March 15, 2018.

*Estimated Losses from Third-Party Claims*

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation.

In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court or jury would agree with the Utility.

The Utility currently believes that it is probable that it will incur a loss of at least $1.1 billion, increased from the $750 million previously estimated as of December 31, 2016, in connection with the Butte fire. The Utility's updated estimate resulted primarily from an increase in the number of claims filed against the Utility and experience to date in resolving claims. This amount is based on updated assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and certain other damages, but does not include punitive damages for which the Utility could be liable. In addition, while this amount includes the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Utility still does not have sufficient information to reasonably estimate the probable loss it may have for these additional claims.

The Utility currently is unable to reasonably estimate the upper end of the range of losses due to the uncertainty of pending legal motions related to the applicability of inverse condemnation and punitive damages and because it has insufficient information on the claims of over 1,000 households and the claims from the OES and the County of Calaveras. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs, results from the ongoing mediation and settlement process, review of potential claims from the OES and the County of Calaveras, outcomes of future court or jury decisions, and information about damages, including punitive damages, that the Utility could be liable for, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

The following table presents changes in the third-party claims liability since December 31, 2015. The balance for the third-party claims liability is included in Other current liabilities in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| **Loss Accrual (in millions)** | | |
|---|---|---|
| Balance at December 31, 2015 | $ | - |
| Accrued losses | | 750 |
| Payments[(1)] | | (60) |
| **Balance at December 31, 2016** | | **690** |
| Accrued losses | | 350 |
| Payments[(1)] | | (479) |
| **Balance at December 31, 2017** | **$** | **561** |

[(1)] As of December 31, 2017 the Utility entered into settlement agreements in connection with the Butte fire corresponding to approximately $624 million of which
$539 million has been paid by the Utility.

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $87 million in connection with the Butte fire. For the year ended December 31, 2017, the Utility has incurred legal expenses in connection with the Butte fire of $60 million.



*Loss Recoveries*

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through December 31, 2017, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, in the year ended December 31, 2017, the Utility received $53 million of reimbursements from the insurance policies of one of its vegetation management contractors (excluded from the table below). Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

| **Insurance Receivable (in millions)** | | |
|---|---|---|
| Balance at December 31, 2015 | $ | - |
| Accrued insurance recoveries | | 625 |
| Reimbursements | | (50) |
| **Balance at December 31, 2016** | | **575** |
| Accrued insurance recoveries | | 297 |
| Reimbursements | | (276) |
| **Balance at December 31, 2017** | **$** | **596** |

In January 2018, the Utility received another $75 million in insurance reimbursements.

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals.

*Regulatory Citations*
On April 25, 2017, the SED issued two citations to the Utility in connection with the Butte fire, totaling $8.3 million. The SED's investigation found that neither the Utility nor its vegetation management contractors took appropriate steps to prevent the gray pine from leaning and contacting the Utility's electric line, which created an unsafe and dangerous condition that resulted in that tree leaning and making contact with the electric line, thus causing a fire. The Utility paid the citations in June 2017.

***Enforcement Matters***
In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

***CPUC Matters***
*Order Instituting an Investigation into Compliance with Ex Parte Communication Rules*
During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have occurred or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker or a commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.
On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices.



On March, 28, 2017, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility jointly submitted to the CPUC a settlement agreement in connection with the OII into the Utility's compliance with the CPUC's ex parte communication rules. On September 1, 2017, the assigned administrative law judge issued a PD in this proceeding adopting, with one modification, the settlement agreement jointly submitted to the CPUC on March 28, 2017, by the Utility, the Cities of San Bruno and San Carlos, the ORA, the SED, and TURN.
If adopted, the PD would increase the payment to the California General Fund, relative to the settlement agreement, from $1 million to $12 million resulting in a total penalty of $97.5 million comprised of: (1) a $12 million payment to the California General Fund, (2) forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million), (3) a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over the Utility's next GRC cycle (i.e., the GRC following the 2017 GRC), and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above.
On September 21, 2017, the Utility submitted a motion to the CPUC accepting the proposed modification of the settlement agreement to increase the Utility's payment to the California General Fund from $1 million to $12 million. Further, the Utility also reported that it has identified several communications that appear to raise issues similar to other communications that are part of this proceeding.
On November 1, 2017, the Utility filed a status report advising the CPUC that the Utility and the non-Utility parties to the settlement agreement were unable to reach an agreement with respect to how to proceed regarding the communications that the Utility reported to the CPUC on September 21, 2017. Also on November 1, 2017, the non-Utility parties to the settlement requested that the CPUC approve the settlement, as modified by the PD, and open a second phase of the OII to investigate and consider appropriate sanctions for the new communications reported by the Utility on September 21, 2017, and others that may be discovered.
On November 30, 2017, the CPUC issued a decision extending the statutory deadline to June 29, 2018 to resolve the proceeding. The CPUC stated that an extension of the statutory deadline was necessary to allow the assigned administrative law judge time to prepare the revised decision and to open and resolve a second phase of this proceeding.
The Utility is unable to predict the outcome of this proceeding.

At December 31, 2017, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $24 million accrual for the amounts payable to the California General Fund and the Cities of San Bruno and San Carlos. In accordance with accounting rules, adjustments related to revenue requirements would be recorded in the periods in which they are incurred.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.



*Potential Safety Citations*

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. There are a number of audit findings, as well as other potential violations identified through various investigations and the Utility's self-reported non-compliance with laws and regulations, on which the SED has yet to act. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation.

The SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED also has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The SED also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged. Historically, the SED has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. In the past, the SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The CPUC can also open an OII and levy additional fines even after the SED has issued a citation.

The Utility is unable to reasonably estimate the amount or range of future charges as a result of SED investigations or any proceedings that could be commenced in connection with potential violations of electric and natural gas laws and regulations.

***Other Matters***

*Other Contingencies*

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $86 million at December 31, 2017 and $45 million at December 31, 2016. These amounts are included in Other current liabilities in the Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowances are reflected in operating and maintenance expenses in the Consolidated Statements of Income. Disallowances as a result of the CPUC's June 2016 final phase one decision and December 2016 final phase two decision in the Utility's 2015 GT&S rate case, the Utility's Pipeline Safety Enhancement Plan, and CPUC's final decision on the closure of Diablo Canyon are discussed below.

*2015 GT&S Rate Case Disallowance of Capital Expenditures*

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also established various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way balancing accounts. As a result, in 2016, the Utility incurred charges of $219 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This included $134 million for 2011 through 2014 capital expenditures in excess of adopted amounts and $85 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending.



*Capital Expenditures Relating to Pipeline Safety Enhancement Plan*

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of December 31, 2017, the Utility has spent $1.38 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected to exceed the authorized amount. The Utility expects the remaining PSEP work to continue throughout 2018. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

*Capital Expenditures Relating to the Diablo Canyon Power Plant*

On January 11, 2018, the CPUC issued a final decision adopting the settlement agreement jointly submitted to the CPUC in May 2017 related to the recovery of license renewal costs and cancelled project costs within the Utility's application to retire Diablo Canyon. The final decision allows for recovery from customers of $18.6 million of the total license renewal project cost of $53 million evenly over an 8-year period beginning January 1, 2018. Related to cancelled project costs, the decision allows for recovery from customers of 100% of the direct costs incurred prior to June 30, 2016 and 25% recovery of direct costs incurred after June 30, 2016. During the year ended December 31, 2017, the Utility incurred charges of $47 million related to the Diablo Canyon capital expenditures settlement agreement, of which $24 million is for cancelled projects and $23 million is for disallowed license renewal costs. The Utility does not expect to incur additional charges as a result of the CPUC's final decision, other than additional project cancellation costs that the Utility does not expect to be material.

**Environmental Remediation Contingencies**

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Key factors that inform the development of

estimated costs include site feasibility studies and investigations, applicable remediation actions, operations and maintenance activities, post-remediation monitoring, and the cost of technologies that are expected to be approved to remediate the site. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **December 31 2017** | **December 31, 2016** |
| Topock natural gas compressor station | $ 334 | $ 299 |
| Hinkley natural gas compressor station | 147 | 135 |
| Former manufactured gas plant sites owned by the Utility or third parties[1] | 320 | 285 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites[2] | 115 | 131 |
| Fossil fuel-fired generation facilities and sites[3] | 123 | 108 |
| **Total environmental remediation liability** | **$ 1,039** | **$ 958** |

[1] Primarily driven by the following sites: Vallejo, SF East Harbor, Napa, and SF North Beach
[2] Primarily driven by the Shell Pond site
[3] Primarily driven by the SF Potrero Power Plant site

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the state and federal regulatory agencies under the federal Resource Conservation and Recovery Act and/or other state hazardous waste laws. The Utility has a comprehensive program in place designed to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at December 31, 2017 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to implement final remediation plans and the Utility's required time frame for remediation. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition and cash flows during the period in which they are recorded. At December 31, 2017, the Utility expected to recover $725 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC.



***Natural Gas Compressor Station Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment.

*Topock Site*

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. On December 21, 2017 the DTSC issued its final environmental impact report. The environmental impact report includes requirements related to conditions of work that have been anticipated or previously required and are accounted for in the current environmental remediation liability. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $289 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered through the HSM, where 90% of the costs are recovered in rates.

*Hinkley Site*

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. The background study is expected to be finalized in 2019. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $145 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

***Former Manufactured Gas Plants ("MGPs")***

Former manufactured gas plants used coal and oil to produce gas for use by the Utility's customers in the past. The by-products and residues of this process were often disposed at the manufactured gas plants themselves. The Utility has undertaken a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $343 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

***Utility-Owned Generation Facilities and Third-Party Disposal Sites***

Utility-owned generation facilities and third-party disposal sites are long-term projects that are undergoing a remediation process. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $145 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

***Fossil Fuel-Fired Generation Sites***

In 1998 the Utility divested its generation power plant business as part of generation deregulation. Although the Utility has sold its fossil-fueled power plants, the Utility has retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $106 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.



**Nuclear Insurance**

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

In addition to the nuclear insurance the Utility maintains through the NEIL, the Utility also is a member of the EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at Diablo Canyon.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2017, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $57 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $3 million, as of December 31, 2017.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $13.5 billion. The Utility purchased the maximum available public liability insurance of $450 million for Diablo Canyon. The balance of the $13.5 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a maximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $450 million per incident. In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the liability insurance.



**Resolution of Remaining Chapter 11 Disputed Claims**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

At December 31, 2017 and December 31, 2016, respectively, the Consolidated Balance Sheets reflected $243 million and $236 million in net claims within Disputed claims and customer refunds. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

**Purchase Commitments**

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2017:

| | Power Purchase Agreements | | | | | |
|---|---|---|---|---|---|---|
| **(in millions)** | **Renewable Energy** | **Conventional Energy** | **Other** | **Natural Gas** | **Nuclear Fuel** | **Total** |
| 2018 | $ 2,150 | $ 718 | $ 280 | $ 388 | $ 96 | $ 3,632 |
| 2019 | 2,193 | 706 | 221 | 167 | 102 | 3,389 |
| 2020 | 2,188 | 686 | 175 | 148 | 143 | 3,340 |
| 2021 | 2,168 | 588 | 153 | 93 | 70 | 3,072 |
| 2022 | 1,975 | 512 | 143 | 93 | 60 | 2,783 |
| Thereafter | 26,005 | 657 | 526 | 357 | 151 | 27,696 |
| **Total purchase** | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| **commitments** | **$ 36,679** | **$ 3,867** | **$ 1,498** | **$ 1,246** | **$ 622** | **$ 43,912** |



***Third-Party Power Purchase Agreements***

In the ordinary course of business, the Utility enters into various agreements, including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

*Renewable Energy Power Purchase Agreements.* In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow. As of December 31, 2017, renewable energy contracts expire at various dates between 2018 and 2043.

*Conventional Energy Power Purchase Agreements.* The Utility has entered into power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2017, these power purchase agreements expire at various dates between 2018 and 2033.

*Other Power Purchase Agreements.* The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Several of these agreements are treated as capital leases. At December 31, 2017 and 2016, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $18 million and $35 million including accumulated amortization of $143 million and $148 million, respectively. The present value of the future minimum lease payments due under these agreements included $11 million and $17 million in Current Liabilities and $7 million and $18 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2017, QF contracts in operation expire at various dates between 2018 and 2028. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The costs incurred for all power purchases and electric capacity amounted to $3.3 billion in 2017, $3.5 billion in 2016, and $3.5 billion in 2015.

***Natural Gas Supply, Transportation, and Storage Commitments***

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2018 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads. Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $0.9 billion in 2017, $0.7 billion in 2016, and $0.9 billion in 2015.



Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2018 and 2025 and are intended to ensure long-term nuclear fuel supply. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices. Payments for nuclear fuel amounted to $83 million in 2017, $100 million in 2016, and $128 million in 2015.

**Other Commitments**

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2018 and 2052. At December 31, 2017, the future minimum payments related to these commitments were as follows:

| (in millions) | | Operating Leases |
|---|---|---|
| 2018 | $ | 44 |
| 2019 | | 41 |
| 2020 | | 40 |
| 2021 | | 36 |
| 2022 | | 27 |
| Thereafter | | 138 |
| **Total minimum lease payments** | **$** | **326** |

Payments for other commitments related to operating leases amounted to $45 million in 2017, $43 million in 2016, and $41 million in 2015. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.



**QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)**

| | Quarter ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **(in millions, except per share amounts)** | | **December 31** | | **September 30** | | **June 30** | | **March 31** |
| **2017** | | | | | | | | |
| **PG&E CORPORATION** | | | | | | | | |
| Operating revenues [1] | $ | 4,100 | $ | 4,517 | $ | 4,250 | $ | 4,268 |
| Operating income | | 429 | | 899 | | 748 | | 880 |
| Income tax provision [2] | | 108 | | 160 | | 134 | | 109 |
| Net income [3] | | 118 | | 553 | | 410 | | 579 |
| Income available for common shareholders | | 114 | | 550 | | 406 | | 576 |
| Comprehensive income | | 118 | | 553 | | 411 | | 579 |
| Net earnings per common share, basic | | 0.22 | | 1.07 | | 0.79 | | 1.13 |
| Net earnings per common share, diluted | | 0.22 | | 1.07 | | 0.79 | | 1.13 |
| Common stock price per share: | | | | | | | | |
| High | | 69.20 | | 71.56 | | 69.22 | | 67.86 |
| Low | | 44.45 | | 65.04 | | 65.33 | | 60.07 |
| **UTILITY** | | | | | | | | |
| Operating revenues [1] | $ | 4,101 | $ | 4,516 | $ | 4,250 | $ | 4,271 |
| Operating income | | 434 | | 834 | | 749 | | 883 |
| Income tax provision [2] | | 33 | | 138 | | 136 | | 120 |
| Net income [3] | | 200 | | 513 | | 409 | | 569 |
| Income available for common stock | | 196 | | 510 | | 405 | | 566 |
| Comprehensive income | | 203 | | 513 | | 409 | | 570 |
| | | | | | | | | |
| **2016** | | | | | | | | |
| **PG&E CORPORATION** | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Operating revenues [4] | $ | 4,713 | $ | 4,810 | $ | 4,169 | $ | 3,974 |
| Operating income | | 1,041 | | 640 | | 401 | | 95 |
| Income tax (benefit) provision [5] | | 160 | | 70 | | 12 | | (187) |
| Net income [6] | | 696 | | 391 | | 210 | | 110 |
| Income available for common shareholders | | 692 | | 388 | | 206 | | 107 |
| Comprehensive income | | 694 | | 391 | | 210 | | 110 |
| Net earnings per common share, basic | | 1.37 | | 0.77 | | 0.41 | | 0.22 |
| Net earnings per common share, diluted | | 1.36 | | 0.77 | | 0.41 | | 0.22 |
| Common stock price per share: | | | | | | | | |
| High | | 62.12 | | 65.39 | | 63.92 | | 59.72 |
| Low | | 58.04 | | 60.82 | | 56.62 | | 51.29 |
| **UTILITY** | | | | | | | | |
| Operating revenues [4] | $ | 4,714 | $ | 4,809 | $ | 4,169 | $ | 3,975 |
| Operating income | | 1,044 | | 640 | | 401 | | 96 |
| Income tax (benefit) provision [5] | | 169 | | 73 | | 13 | | (185) |
| Net income [6] | | 696 | | 389 | | 209 | | 108 |
| Income available for common stock | | 692 | | 386 | | 205 | | 105 |
| Comprehensive income | | 694 | | 389 | | 210 | | 108 |

(1) In the first quarter of 2017, the Utility recorded the remaining retroactive revenues related to the 2015 GT&S rate case decision authorized by the CPUC.

(2) In the fourth quarter of 2017, the Utility had lower income tax expense primarily due to lower operating income, which was partially offset by the impact of the Tax Act.



(3) In the second quarter of 2017, the Utility recorded a $47 million disallowance related to the Diablo Canyon settlement. Also, in the third quarter of 2017, the Utility recorded a $350 million charge related to Butte fire third-party claims. In the first, second, and third quarters of 2017, the Utility recorded $7 million, $14 million, and $276 million, respectively, for probable insurance recoveries in connection with recovery of losses related to the Butte fire. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

(4) In the third and fourth quarters of 2016, the Utility recorded an increase in base revenues as authorized by the CPUC in the 2015 GT&S rate case decision.

(5) In the first quarter of 2016, the Utility had an income tax benefit, primarily due to net loss before income taxes and various tax audit results.

(6) In the first, second, and third quarters of 2016, the Utility recorded charges for disallowed capital spending of $87 million, $148 million, and $51 million, respectively, as a result of the San Bruno Penalty Decision. Additionally, in the second and fourth quarters of 2016, the Utility recorded charges of $190 million and $29 million for capital expenditures probable of disallowance related to the final decision in the 2015 GT&S rate case. Also, in the first quarter of 2016 the Utility recorded a $350 million charge related to Butte fire litigation. In the second quarter of 2016, the Utility recorded $260 million for probable insurance recoveries in connection with recovery of losses related to the Butte fire. In the fourth quarter of 2016, the Utility recorded a $400 million charge related to the Butte fire litigation and an insurance receivable of $365 million for probable insurance recoveries in connection with the Butte fire. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)



## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and the Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of

PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2017.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.



**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
PG&E Corporation

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 9, 2018, expressed an unqualified opinion on those consolidated financial statements and included an emphasis-of-matter paragraph regarding uncertainty related to possible material losses or penalties to the Company as a result of the Northern California wildfires that occurred in October 2017, as discussed in Note 13 to the consolidated financial statements.

**Basis for Opinion**

The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail,

accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent, or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 9, 2018



**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
Pacific Gas and Electric Company

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Utility and our report dated February 9, 2018, expressed an unqualified opinion on those consolidated financial statements and included an emphasis-of-matter paragraph regarding uncertainty related to possible material losses or penalties to the Utility as a result of the Northern California wildfires that occurred in October 2017, as discussed in Note 13 to the consolidated financial statements.

**Basis for Opinion**

The Utility’s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management’s Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Utility’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

**Definition and Limitations of Internal Control over Financial Reporting**

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent, or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that

controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018



**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
PG&E Corporation

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the Company's related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 9, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

**Emphasis of Matter**

As discussed in Note 13 to the consolidated financial statements, the Northern California wildfires that occurred in October 2017 may result in material losses or penalties to the Company.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018

We have served as the Company's auditor since 1999.



**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
Pacific Gas and Electric Company

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2017 and 2016, and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Utility as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Utility's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 9, 2018 expressed an unqualified opinion on the Utility's internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of the Utility's management. Our responsibility is to express an opinion on the Utility's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

**Emphasis of Matter**

As discussed in Note 13 to the consolidated financial statements, the Northern California wildfires that occurred in October 2017 may result in material losses or penalties to the Utility.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 9, 2018
We have served as the Utility's auditor since 1999.

**ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**

Not applicable.

**ITEM 9A. CONTROLS AND PROCEDURES**

**Evaluation of Disclosure Controls and Procedures**

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2017, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

**Management's Annual Report on Internal Control over Financial Reporting**

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this 2017 Form 10-K under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

**Registered Public Accounting Firm's Report on Internal Control over Financial Reporting**

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**Changes in Internal Control Over Financial Reporting**

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

**ITEM 9B. OTHER INFORMATION**

Not applicable.

**PART III**

**ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE**

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this 2017 Form 10-K. Other information regarding directors will be included under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on the Corporate Governance section of PG&E Corporation's website (*www.pgecorp.com/corp/about-us/corporate-governance.page*) and on the Utility's website (*www.pge.com/en_US/about-pge/company-information/company-information.page*, under the "Visit Corporate Governance" link): (1) the PG&E Corporation's and the Utility's codes of conduct (which meet the definition of "code of ethics" of Item 406(b) of the SEC Regulation S-K) adopted by PG&E Corporation and the Utility and applicable to their directors and employees, including their respective Chief Executive Officer and President, as the case may be, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's respective corporate governance guidelines, and (3) key Board committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the code of conduct adopted by PG&E Corporation and the Utility and that apply to their respective Chief Executive Officer and President, as the case may be, Chief Financial Officers, or Controllers, PG&E Corporation and the Utility will post the amended code of ethics on their websites and will disclose any waivers to the "code of ethics" in a Current Report on Form 8-K.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

There were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2017 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial experts" as defined by the SEC will be included under the headings "Corporate Governance - Board Committee Duties - Audit Committees" and "Corporate Governance - Committee Membership, Independence, and Qualifications" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 11. EXECUTIVE COMPENSATION

Information responding to Item 11, for each of PG&E Corporation and the Utility, will be included under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2017," "Grants of Plan-Based Awards in 2017," "Outstanding Equity Awards at Fiscal Year End - 2017," "Option Exercises and Stock Vested During 2017," "Pension Benefits - 2017," "Non-Qualified Deferred Compensation - 2017," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors - 2017 Director Compensation" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings “Share Ownership Information - Security Ownership of Management” and “Share Ownership Information - Principal Shareholders” in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

***Equity Compensation Plan Information***

The following table provides information as of December 31, 2017 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| | (a) | | (b) | (c) |
|---|---|---|---|---|
| **Plan Category** | **Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights** | | **Weighted Average Exercise Price of Outstanding Options, Warrants and Rights** | **Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))** |
| Equity compensation plans approved by shareholders | 4,969,352 [(1)] | $ | 35.53 [(2)] | 14,381,959 [(3)] |
| Equity compensation plans not approved by shareholders | - | | - | - |
| Total equity compensation plans | 4,969,352 [(1)] | $ | 35.53 [(2)] | 14,381,959 [(3)] |

(1) Includes 14,041 phantom stock units, 1,426,371 restricted stock units and 3,524,850 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares granted in 2015, reflects the actual payout percentage of 0% for performance shares using a total shareholder return metric and 15.1%for performance shares using safety and affordability metrics. The actual number of shares issued can range from 0% to 200% of target depending on achievement of performance objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) This is the weighted average exercise price for the 4,090 options outstanding as of December 31, 2017.

(3) Represents the total number of shares available for issuance under all of PG&E Corporation’s equity compensation plans as of December 31, 2017. Stock-based awards granted under these plans include restricted stock units, performance shares and phantom stock units. The 2014 LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the 2014 LTIP, less approximately 2.7 million shares for awards granted under the 2006 LTIP from January 1, 2014 through May 11, 2014. In addition, if any awards outstanding under the 2006 LTIP at December 31, 2013 are cancelled, forfeited or expire without being settled in full, shares of stock allocable to the terminated portion of such awards shall again be available for issuance under the 2014 LTIP.

For more information, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

**ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE**

Information responding to Item 13, for each of PG&E Corporation and the Utility, will be included under the headings “Related Party Transactions” and “Corporate Governance - Board and Director General Independence and Qualifications” and “Corporate Governance - Committee Membership, Independence, and Qualifications” in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

Information responding to Item 14, for each of PG&E Corporation and the Utility, will be included under the heading "Information Regarding the Independent Auditor for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.



## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

**a. The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as part of this report in Item 8:

Consolidated Statements of Income for the Years Ended December 31, 2017, 2016, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2017, 2016, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.
Consolidated Balance Sheets at December 31, 2017 and 2016 for each of PG&E Corporation and Pacific Gas and Electric Company.
Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.
Consolidated Statements of Equity for the Years Ended December 31, 2017, 2016, and 2015 for PG&E Corporation.
Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2017, 2016, and 2015 for Pacific Gas and Electric Company.
Notes to the Consolidated Financial Statements.
Quarterly Consolidated Financial Data (Unaudited).
Management's Report on Internal Controls
Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Condensed Financial Information of Parent as of December 31, 2017 and 2016 and for the Years Ended December 31, 2017, 2016, and 2015.
Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2017, 2016, and 2015.

3. Exhibits required by Item 601 of Regulation S-K



**EXHIBIT INDEX**

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of December 16, 2016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 3.3) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 12, 2004 (File No. 1-2348), Exhibit 3) |

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| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of December 16, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2016 (File No. 1-2348), Exhibit 3.5) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture, dated as of March 13, 2007, relating to the issuance of $700,000,000 principal amount of Pacific Gas and Electric Company's 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Third Supplemental Indenture, dated as of March 3, 2008, relating to the issuance of $400,000,000 of Pacific Gas and Electric Company's 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Fourth Supplemental Indenture, dated as of October 21, 2008, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fifth Supplemental Indenture, dated as of November 18, 2008, relating to the issuance of $200,000,000 principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Sixth Supplemental Indenture, dated as of March 6, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Seventh Supplemental Indenture, dated as of June 11, 2009, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due June 10, 2010 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 11, 2009 (File No. 1-2348), Exhibit 4.1) |



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| 4.8 | Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture, dated as of April 1, 2010, relating to the issuance of $250,000,000 aggregate principal amount of its 5.80% Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |

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| 4.10 | Tenth Supplemental Indenture, dated as of September 15, 2010, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture, dated as of November 18, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of its 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture, dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture, dated as of September 12, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.14 | Sixteenth Supplemental Indenture, dated as of December 1, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture, dated as of April 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture, dated as of August 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of its 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Nineteenth Supplemental Indenture, dated as of June 14, 2013, relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture, dated as of November 12, 2013, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company’s 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |

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| 4.19 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No.1 2348), Exhibit 4.1) |
| 4.20 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1-2348), Exhibit 4.1) |
| 4.21 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1-2348), Exhibit 4.1) |
| 4.22 | Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.23 | Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.24 | Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.25 | Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 30, 2017 and $400,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.26 | Twenty-Ninth Supplemental Indenture, dated as of March 10, 2017, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.30% Senior Notes due March 15, 2027 and $200,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 10, 2017 (File No. 1-2348), Exhibit 4.1) |
| 4.27 | Indenture, dated as of November 29, 2017, relating to the issuance of $500,000,000 aggregate principal amount of by Pacific Gas and Electric Company's Floating Rate Senior Notes due 2018, $1,150,000,000 aggregate principal amount of its 3.30% Senior Notes due 2027 and $850,000,000 aggregate principal amount of its 3.95% Senior Notes due 2047 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 4.1) |
| 4.28 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |

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| 4.29 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |



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| 4.30 | Registration Rights Agreement, dated as of November 29, 2017, among Pacific Gas and Electric Company and Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 4.5) |
| 10.1 | Second Amended and Restated Credit Agreement, dated as of April 27, 2015, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank, National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | Second Amended and Restated Credit Agreement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 2, 2016 (File No. 1-2348), Exhibit 10.1) |
| 10.4 | Term Loan Agreement, dated as of February 23, 2017, by and among Pacific Gas and Electric Company, the several banks and other financial institutions or entities from time to time parties thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd. and U.S. Bank National Association, as joint lead arrangers and joint bookrunners and The Bank of Tokyo-Mitsubishi UFJ, Ltd, as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 23, 2017 (File No. 1-2348), Exhibit 10.1) |
| 10.5 | Purchase Agreement, dated as of November 27, 2017, among Pacific Gas and Electric Company and Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers listed on Schedules I-A, I-B and I-C thereto (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 10.1) |

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| 10.6 | | Settlement Agreement among the California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K dated December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.7 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.8 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |



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| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.04) |
| 10.10 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.7) |
| 10.11 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.7) |
| 10.12 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4) |
| 10.13 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.14 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.05) |
| 10.15 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.12) |
| 10.16 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.8) |

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|---|---|---|
| 10.17 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.06) |
| 10.18 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.14) |
| 10.19 | * | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.9) |
| 10.20 | * | Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5) |
| 10.21 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-2609), Exhibit 10.16) |
| 10.22 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for non-annual award under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.08) |



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|---|---|---|
| 10.23 | * | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-2609), Exhibit 10.17) |
| 10.24 | * | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-2609), Exhibit 10.18) |
| 10.25 | * | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.4) |
| 10.26 | * | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.5) |
| 10.27 | * | Non-Annual Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.6) |

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| 10.28 | * | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.7) |
| 10.29 | * | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.8) |
| 10.30 | * | Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.31 | * | Separation Agreement between PG&E Corporation and Hyun Park dated August 7, 2017 and amended as of September 1, 2017 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2017 (File No. 1-12609), Exhibit 10.1) |
| 10.32 | * | Separation Agreement between Pacific Gas and Electric Company and Desmond Bell dated January 6, 2017 and amended as of April 25, 2017 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-2348), Exhibit 10.09) |
| 10.33 | * | Separation Agreement between Pacific Gas and Electric Company and Helen Burt dated January 5, 2017 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2017 (File No. 1-2348), Exhibit 10.3) |
| 10.34 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and David Thomason dated May 24, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-2348), Exhibit 10.2) |
| 10.35 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and David S. Thomason dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-2348), Exhibit 10.1) |
| 10.36 | * | Performance Share Award Agreement subject to financial goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.2) |



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| 10.37 | * | Performance Share Award Agreement subject to safety and customer affordability goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.3) |
| 10.38 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Edward D. Halpin dated November 28, 2016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.32) |
| 10.39 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |

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| 10.40 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.41 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.42 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.43 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2017 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended March 31, 2017 (File No. 1-12609), Exhibit 10.2) |
| 10.44 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2016 (incorporated by reference to PG&E Corporation’s Form 8-K dated February 16, 2016 (File No. 1-12609) |
| 10.45 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.46 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.47 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.48 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.49 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2015 (File No. 1-2348), Exhibit 10.38) |
| 10.50 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 16, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-2348), Exhibit 10.4) |



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| 10.51 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6, 2015 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2014) (File No. 1-2348), Exhibit 10.37) |

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| 10.52 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.53 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.27) |
| 10.54 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2018 |
| 10.55 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective February 15, 2017 |
| 10.56 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-12609), Exhibit 10.42) |
| 10.57 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.58 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.59 | * | Form of Restricted Stock Unit Agreement for 2017 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.07) |
| 10.60 | * | Form of Restricted Stock Unit Agreement for 2016 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609), Exhibit 10.1) |
| 10.61 | * | Form of Restricted Stock Unit Agreement for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.01) |
| 10.62 | * | Form of Restricted Stock Unit Agreement for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.55) |
| 10.63 | * | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.4) |
| 10.64 | * | Form of Restricted Stock Unit Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.65 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |

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| 10.66 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 8-K dated January 6, 2005 (File No. 1-12609), Exhibit 99.1) |



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| 10.67 | * | Form of Performance Share Agreement subject to financial goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.02) |
| 10.68 | * | Form of Performance Share Agreement subject to financial goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.61) |
| 10.69 | * | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.5) |
| 10.70 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.03) |
| 10.71 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.63) |
| 10.72 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.6) |
| 10.73 | * | Form of Performance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3) |
| 10.74 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.75 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.76 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.77 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.78 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |

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| 10.79 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.80 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.2) |
| 10.81 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.82 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.83 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |



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|---|---|---|
| 12.1 | | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 21 | | Subsidiaries of the Registrant |
| 23.1 | | PG&E Corporation Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 23.2 | | Pacific Gas and Electric Company Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |
| * | | Management contract or compensatory agreement. |

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.



**ITEM 16. FORM 10-K SUMMARY**

None.



**SIGNATURES**

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2017 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| | PG&E CORPORATION<br>(Registrant) | | PACIFIC GAS AND ELECTRIC COMPANY<br>(Registrant) |
|---|---|---|---|
| | GEISHA J. WILLIAMS | | NICKOLAS STAVROPOULOS |
| | Geisha J. Williams | | Nickolas Stavropoulos |
| By: | Chief Executive Officer and President | By: | President and Chief Operating Officer |
| Date: | February 9, 2018 | Date: | February 9, 2018 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| **Signature** | **Title** | **Date** |
|---|---|---|
| **A. Principal Executive Officers** | | |
| GEISHA J. WILLIAMS<br>Geisha J. Williams | Chief Executive Officer and President (PG&E Corporation) | February 9, 2018 |
| NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | President and Chief Operating Officer (Pacific Gas and Electric Company) | February 9, 2018 |
| **B. Principal Financial Officers** | | |
| JASON P. WELLS<br>Jason P. Wells | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 9, 2018 |
| DAVID S. THOMASON<br>David S. Thomason | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 9, 2018 |

**C. Principal Accounting Officer**

| | | |
|---|---|---|
| DAVID S. THOMASON<br>David S. Thomason | Vice President and Controller (PG&E Corporation)<br>Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 9, 2018 |

**D. Directors (PG&E Corporation and Pacific Gas and Electric Company, unless otherwise noted)**

| | | |
|---|---|---|
| * LEWIS CHEW<br>Lewis Chew | Director | February 9, 2018 |



| | | |
|---|---|---|
| * FRED J. FOWLER<br>Fred J. Fowler | Director | February 9, 2018 |
| * JEH C. JOHNSON<br>Jeh C. Johnson | Director (PG&E Corporation only) | February 9, 2018 |
| * RICHARD C. KELLY<br>Richard C. Kelly | Director<br>Chair of the Board (PG&E Corporation) | February 9, 2018 |
| * ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 9, 2018 |
| * RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 9, 2018 |
| * FORREST E. MILLER<br>Forrest E. Miller | Director<br>Chair of the Board (Pacific Gas and Electric Company) | February 9, 2018 |
| * ERIC D. MULLINS<br>Eric D. Mullins | Director | February 9, 2018 |
| * ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 9, 2018 |
| * BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 9, 2018 |

| | | |
|---|---|---|
| * ANNE SHEN SMITH<br>Anne Shen Smith | Director | February 9, 2018 |
| * NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | Director (Pacific Gas and Electric Company only) | February 9, 2018 |
| * GEISHA J.WILLIAMS<br>Geisha J. Williams | Director | February 9, 2018 |
| *By:<br>John R. Simon, Attorney-in-Fact | | February 9, 2018 |



**PG&E CORPORATION**
**SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2017** | **2016** | **2015** |
| Administrative service revenue | $ 63 | $ 70 | $ 51 |
| Operating expenses | (5) | (73) | (53) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (11) | (10) | (10) |
| Other income | 4 | 2 | 30 |
| Equity in earnings of subsidiaries | 1,667 | 1,388 | 852 |
| Income before income taxes | 1,719 | 1,378 | 871 |
| Income tax provision (benefit) | 73 | (15) | (3) |
| **Net income** | **$ 1,646** | **$ 1,393** | **$ 874** |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $1, and $0, at respective dates) | $ 1 | $ (2) | $ (1) |
| Net change in investments (net of taxes of $0, $0, and $12, at respective dates) | - | - | (17) |
| Total other comprehensive income (loss) | 1 | (2) | (18) |
| **Comprehensive Income** | **$ 1,647** | **$ 1,391** | **$ 856** |
| **Weighted Average Common Shares Outstanding, Basic** | **512** | **499** | **484** |
| **Weighted Average Common Shares Outstanding, Diluted** | **513** | **501** | **487** |
| **Net earnings per common share, basic** | **$ 3.21** | **$ 2.79** | **$ 1.81** |
| **Net earnings per common share, diluted** | **$ 3.21** | **$ 2.78** | **$ 1.79** |



**PG&E CORPORATION**

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF PARENT - (Continued)
CONDENSED BALANCE SHEETS

| (in millions) | Balance at December 31, 2017 | 2016 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 2 | $ 106 |
| Advances to affiliates | 24 | 24 |
| Income taxes receivable | 27 | 25 |
| **Total current assets** | **53** | **155** |
| **Noncurrent Assets** | | |
| Equipment | 3 | 2 |
| Accumulated depreciation | (3) | (2) |
| **Net equipment** | **-** | **-** |
| Investments in subsidiaries | 19,514 | 18,172 |
| Other investments | 144 | 133 |
| Intercompany receivable | 72 | - |
| Deferred income taxes | 123 | 267 |
| **Total noncurrent assets** | **19,853** | **18,572** |
| **Total Assets** | **$ 19,906** | **$ 18,727** |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 132 | $ - |
| Accounts payable - other | 6 | 7 |
| Other | 23 | 274 |
| **Total current liabilities** | **161** | **281** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 350 | 348 |
| Other | 175 | 158 |
| **Total noncurrent liabilities** | **525** | **506** |
| **Common Shareholders' Equity** | | |
| Common stock | 12,632 | 12,198 |
| Reinvested earnings | 6,596 | 5,751 |
| Accumulated other comprehensive income (loss) | (8) | (9) |
| **Total common shareholders' equity** | **19,220** | **17,940** |
| **Total Liabilities and Shareholders' Equity** | **$ 19,906** | **$ 18,727** |



PG&E CORPORATION
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF PARENT - (Continued)
CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|
| **Cash Flows from Operating Activities:** | | | |

| | | | |
|---|---|---|---|
| Net income | $ 1,646 | $ 1,393 | $ 874 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 20 | 74 | 66 |
| Equity in earnings of subsidiaries | (1,667) | (1,388) | (852) |
| Deferred income taxes and tax credits-net | 139 | 11 | 10 |
| Current income taxes receivable/payable | (2) | (1) | 5 |
| Other | (75) | (24) | (70) |
| **Net cash provided by operating activities** | **61** | **65** | **33** |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (455) | (835) | (705) |
| Dividends received from subsidiaries [1] | 784 | 911 | 716 |
| **Net cash provided by (used in) investing activities** | **329** | **76** | **11** |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings (repayments) under revolving credit facilities | 132 | - | - |
| Common stock issued | 395 | 822 | 780 |
| Common stock dividends paid [2] | (1,021) | (921) | (856) |
| **Net cash provided by (used in) financing activities** | **(494)** | **(99)** | **(76)** |
| **Net change in cash and cash equivalents** | **(104)** | **42** | **(32)** |
| **Cash and cash equivalents at January 1** | **106** | **64** | **96** |
| **Cash and cash equivalents at December 31** | **$ 2** | **$ 106** | **$ 64** |
| **Supplemental disclosure of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (9) | $ (9) | $ (9) |
| Income taxes, net | - | (13) | - |
| **Supplemental disclosure of noncash investing and financing activities** | | | |
| Noncash common stock issuances | $ 21 | $ 20 | $ 21 |
| Common stock dividends declared but not yet paid | - | 248 | 224 |

[1] Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries as an investing cash flow.
[2] In July and October of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of $0.53 per share. In July and October of 2016 and January and April of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of $0.49 per share. In January, April, July, and October of 2015 and January and April of 2016, respectively, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.



**PG&E Corporation**
**SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2017, 2016, and 2015**

| **(in millions)** | | **Additions** | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions** [2] | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 2017: | | | | | |
| Allowance for uncollectible accounts [1] | $ 58 | $ 55 | $ - | $ 49 | $ 64 |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ - | $ 46 | $ 58 |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |

[1] Allowance for uncollectible accounts is deducted from “Accounts receivable - Customers.”
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.



**Pacific Gas and Electric Company**
**SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 2017, 2016, and 2015**

| **(in millions)** | | **Additions** | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions [2]** | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2017: | | | | | |
| Allowance for uncollectible accounts [1] | $ 58 | $ 55 | $ - | $ 49 | $ 64 |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ - | $ 46 | $ 58 |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |

[1] Allowance for uncollectible accounts is deducted from “Accounts receivable - Customers.”
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

# Exhibit 7

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C., 20549**
**FORM 10-Q**

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2015

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to __________

| Commission File Number | Exact Name of Registrant as Specified in its Charter | State or Other Jurisdiction of Incorporation | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E Corporation | California | 94-3234914 |
| 1-2348 | Pacific Gas and Electric Company | California | 94-0742640 |

| PG&E Corporation | Pacific Gas and Electric Company |
|---|---|
| 77 Beale Street | 77 Beale Street |
| P.O. Box 770000 | P.O. Box 770000 |
| San Francisco, California 94177 | San Francisco, California 94177 |

Address of principal executive offices, including zip code

| PG&E Corporation | Pacific Gas and Electric Company |
|---|---|
| (415) 973-1000 | (415) 973-7000 |

Registrant's telephone number, including area code

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. [X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation: | [X] Yes [ ] No |
| Pacific Gas and Electric Company: | [X] Yes [ ] No |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | | |
|---|---|---|
| PG&E Corporation: | [X] Large accelerated filer | [ ] Accelerated filer |
| | [ ] Non-accelerated filer | [ ] Smaller reporting company |
| Pacific Gas and Electric Company: | [ ] Large accelerated filer | [ ] Accelerated filer |
| | [X] Non-accelerated filer | [ ] Smaller reporting company |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation: | [ ] Yes [X] No |
| Pacific Gas and Electric Company: | [ ] Yes [X] No |

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

| | |
|---|---|
| Common stock outstanding as of April 20, 2015: | |
| PG&E Corporation: | 479,973,603 |
| Pacific Gas and Electric Company: | 264,374,809 |



**PG&E CORPORATION AND**
**PACIFIC GAS AND ELECTRIC COMPANY**
**FORM 10-Q**
**FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2015**

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## GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2014 Form 10-K | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2014 |
| AFUDC | allowance for funds used during construction |
| CAISO | California Independent System Operator |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| EPS | earnings per common share |
| EV | electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| IRS | Internal Revenue Service |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| ORA | Office of Ratepayer Advocates |
| PSEP | pipeline safety enhancement plan |
| Regional Board | California Regional Water Control Board, Lahontan Region |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |

## PART I. FINANCIAL INFORMATION
## ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

| | (Unaudited) | |
|---|---|---|
| | Three Months Ended March 31, | |
| **(in millions, except per share amounts)** | **2015** | **2014** |
| **Operating Revenues** | | |
| Electric | $ 3,013 | $ 3,001 |
| Natural gas | 886 | 890 |
| **Total operating revenues** | **3,899** | **3,891** |
| **Operating Expenses** | | |
| Cost of electricity | 1,000 | 1,210 |
| Cost of natural gas | 274 | 360 |
| Operating and maintenance | 1,923 | 1,299 |
| Depreciation, amortization, and decommissioning | 631 | 538 |
| **Total operating expenses** | **3,828** | **3,407** |
| **Operating Income** | 71 | 484 |
| Interest income | 1 | 3 |
| Interest expense | (189) | (185) |
| Other income, net | 58 | 19 |
| **Income (Loss) Before Income Taxes** | **(59)** | **321** |
| Income tax provision (benefit) | (93) | 91 |
| **Net Income** | **34** | **230** |
| **Preferred stock dividend requirement of subsidiary** | 3 | 3 |
| **Income Available for Common Shareholders** | **$ 31** | **$ 227** |
| **Weighted Average Common Shares Outstanding, Basic** | **477** | **459** |
| **Weighted Average Common Shares Outstanding, Diluted** | **481** | **460** |
| **Net Earnings Per Common Share, Basic** | **$ 0.06** | **$ 0.49** |
| **Net Earnings Per Common Share, Diluted** | **$ 0.06** | **$ 0.49** |
| **Dividends Declared Per Common Share** | **$ 0.46** | **$ 0.46** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| (in millions) | (Unaudited) Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| Net Income | $ 34 | $ 230 |
| **Other Comprehensive Income** | | |
| Pension and other postretirement benefit plans obligations | | |
| (net of taxes of $0 and $0, at respective dates) | - | - |
| Net change in investments | | |
| (net of taxes of $12 and $4, at respective dates) | (17) | 5 |
| **Total other comprehensive income (loss)** | **(17)** | **5** |
| **Comprehensive Income** | **17** | **235** |
| **Preferred stock dividend requirement of subsidiary** | **3** | **3** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 14** | **$ 232** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PG&E CORPORATION**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| (in millions) | (Unaudited) Balance At March 31, 2015 | December 31, 2014 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 145 | $ 151 |
| Restricted cash | 298 | 298 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $60 and $66 at respective dates) | 905 | 960 |
| Accrued unbilled revenue | 651 | 776 |
| Regulatory balancing accounts | 2,227 | 2,266 |
| Other | 314 | 377 |
| Regulatory assets | 451 | 444 |
| Inventories: | | |
| Gas stored underground and fuel oil | 108 | 172 |
| Materials and supplies | 310 | 304 |
| Income taxes receivable | 195 | 198 |
| Other | 422 | 443 |
| **Total current assets** | **6,026** | **6,389** |

| | | |
|---|---|---|
| **Property, Plant, and Equipment** | | |
| Electric | 45,888 | 45,162 |
| Gas | 15,970 | 15,678 |
| Construction work in progress | 2,115 | 2,220 |
| Other | 2 | 2 |
| **Total property, plant, and equipment** | **63,975** | **63,062** |
| Accumulated depreciation | (19,534) | (19,121) |
| **Net property, plant, and equipment** | **44,441** | **43,941** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 6,412 | 6,322 |
| Nuclear decommissioning trusts | 2,526 | 2,421 |
| Income taxes receivable | 94 | 91 |
| Other | 1,048 | 963 |
| **Total other noncurrent assets** | **10,080** | **9,797** |
| **TOTAL ASSETS** | **$ 60,547** | **$ 60,127** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PG&E CORPORATION**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| **(in millions, except share amounts)** | **March 31, 2015** | **December 31, 2014** |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 856 | $ 633 |
| Accounts payable: | | |
| Trade creditors | 1,007 | 1,244 |
| Regulatory balancing accounts | 1,039 | 1,090 |
| Other | 545 | 476 |
| Disputed claims and customer refunds | 446 | 434 |
| Interest payable | 150 | 197 |
| Other | 2,110 | 1,846 |
| **Total current liabilities** | **6,153** | **5,920** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 15,051 | 15,050 |
| Regulatory liabilities | 6,307 | 6,290 |
| Pension and other postretirement benefits | 2,551 | 2,561 |
| Asset retirement obligations | 3,595 | 3,575 |
| Deferred income taxes | 8,626 | 8,513 |
| Other | 2,309 | 2,218 |

| | | |
|---|---|---|
| **Total noncurrent liabilities** | **38,439** | **38,207** |
| **Commitments and Contingencies (Note 9)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 479,490,832 and 475,913,404 shares outstanding at respective dates | 10,583 | 10,421 |
| Reinvested earnings | 5,126 | 5,316 |
| Accumulated other comprehensive income (loss) | (6) | 11 |
| **Total shareholders' equity** | **15,703** | **15,748** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **15,955** | **16,000** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 60,547** | **$ 60,127** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | (Unaudited) | |
|---|---|---|
| | Three Months Ended March 31, | |
| **(in millions)** | **2015** | **2014** |
| **Cash Flows from Operating Activities** | | |
| Net income | $ 34 | $ 230 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 631 | 538 |
| Allowance for equity funds used during construction | (28) | (22) |
| Deferred income taxes and tax credits, net | 113 | 15 |
| Disallowed capital expenditures | 53 | - |
| Other | 52 | 56 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | 236 | 321 |
| Inventories | 58 | 62 |
| Accounts payable | (46) | 31 |
| Income taxes receivable/payable | 3 | (28) |
| Other current assets and liabilities | (114) | (37) |
| Regulatory assets, liabilities, and balancing accounts, net | 195 | (376) |
| Other noncurrent assets and liabilities | (107) | (19) |
| **Net cash provided by operating activities** | **1,080** | **771** |
| **Cash Flows from Investing Activities** | | |
| Capital expenditures | (1,191) | (1,197) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 417 | 530 |
| Purchases of nuclear decommissioning trust investments | (505) | (536) |

| | | |
|---|---|---|
| Other | 7 | 14 |
| **Net cash used in investing activities** | **(1,272)** | **(1,189)** |
| **Cash Flows from Financing Activities** | | |
| Repayments under revolving credit facilities | - | (260) |
| Net issuances of commercial paper, net of discount of $0 and $1 at respective dates | 223 | 15 |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2014 | - | 1,237 |
| Repayments of long-term debt | - | (889) |
| Common stock issued | 151 | 302 |
| Common stock dividends paid | (211) | (202) |
| Other | 23 | 27 |
| **Net cash provided by financing activities** | **186** | **230** |
| **Net change in cash and cash equivalents** | **(6)** | **(188)** |
| **Cash and cash equivalents at January 1** | **151** | **296** |
| **Cash and cash equivalents at March 31** | **$ 145** | **$ 108** |
| **Supplemental disclosures of cash flow information** | | |
| Cash received (paid) for: | | |
| Interest, net of amounts capitalized | $ (216) | $ (199) |
| Income taxes, net | - | 1 |



| | | |
|---|---|---|
| **Supplemental disclosures of noncash investing and financing activities** | | |
| Common stock dividends declared but not yet paid | $ 218 | $ 213 |
| Capital expenditures financed through accounts payable | 217 | 171 |
| Noncash common stock issuances | 5 | 5 |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

| | (Unaudited) Three Months Ended March 31, | |
|---|---|---|
| **(in millions)** | **2015** | **2014** |
| **Operating Revenues** | | |
| Electric | $ 3,014 | $ 3,000 |

| | | |
|---|---|---|
| Natural gas | 886 | 890 |
| **Total operating revenues** | **3,900** | **3,890** |
| **Operating Expenses** | | |
| Cost of electricity | 1,000 | 1,210 |
| Cost of natural gas | 274 | 360 |
| Operating and maintenance | 1,923 | 1,297 |
| Depreciation, amortization, and decommissioning | 631 | 538 |
| **Total operating expenses** | **3,828** | **3,405** |
| **Operating Income** | 72 | 485 |
| Interest income | 1 | 2 |
| Interest expense | (187) | (179) |
| Other income, net | 26 | 20 |
| **Income (Loss) Before Income Taxes** | **(88)** | **328** |
| Income tax provision (benefit) | (92) | 100 |
| **Net Income** | **4** | **228** |
| Preferred stock dividend requirement | 3 | 3 |
| **Income Available for Common Stock** | **$ 1** | **$ 225** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | **Three Months Ended March 31,** | |
|---|---|---|
| **(in millions)** | **2015** | **2014** |
| **Net Income** | **$ 4** | **$ 228** |
| **Other Comprehensive Income** | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0 and $0, at respective dates ) | - | - |
| **Total other comprehensive income (loss)** | - | - |
| **Comprehensive Income** | **$ 4** | **$ 228** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | **(Unaudited)** | |
|---|---|---|
| | **Balance At** | |
| **(in millions)** | **March 31, 2015** | **December 31, 2014** |

| | | | | |
|---|---|---|---|---|
| **ASSETS** | | | | |
| **Current Assets** | | | | |
| Cash and cash equivalents | $ | 50 | $ | 55 |
| Restricted cash | | 298 | | 298 |
| Accounts receivable: | | | | |
| Customers (net of allowance for doubtful accounts of $60 and $66 at respective dates) | | 905 | | 960 |
| Accrued unbilled revenue | | 651 | | 776 |
| Regulatory balancing accounts | | 2,227 | | 2,266 |
| Other | | 333 | | 375 |
| Regulatory assets | | 451 | | 444 |
| Inventories: | | | | |
| Gas stored underground and fuel oil | | 108 | | 172 |
| Materials and supplies | | 310 | | 304 |
| Income taxes receivable | | 166 | | 168 |
| Other | | 408 | | 409 |
| **Total current assets** | | **5,907** | | **6,227** |
| **Property, Plant, and Equipment** | | | | |
| Electric | | 45,888 | | 45,162 |
| Gas | | 15,970 | | 15,678 |
| Construction work in progress | | 2,115 | | 2,220 |
| **Total property, plant, and equipment** | | **63,973** | | **63,060** |
| Accumulated depreciation | | (19,532) | | (19,120) |
| **Net property, plant, and equipment** | | **44,441** | | **43,940** |
| **Other Noncurrent Assets** | | | | |
| Regulatory assets | | 6,412 | | 6,322 |
| Nuclear decommissioning trusts | | 2,526 | | 2,421 |
| Income taxes receivable | | 94 | | 91 |
| Other | | 943 | | 864 |
| **Total other noncurrent assets** | | **9,975** | | **9,698** |
| **TOTAL ASSETS** | **$** | **60,323** | **$** | **59,865** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | | | | |
|---|---|---|---|---|
| | **(Unaudited)** | | | |
| | **Balance At** | | | |
| **(in millions, except share amounts)** | **March 31, 2015** | | **December 31, 2014** | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | | | |
| **Current Liabilities** | | | | |
| Short-term borrowings | $ | 856 | $ | 633 |

| | | |
|---|---|---|
| Accounts payable: | | |
| Trade creditors | 1,007 | 1,243 |
| Regulatory balancing accounts | 1,039 | 1,090 |
| Other | 584 | 444 |
| Disputed claims and customer refunds | 446 | 434 |
| Interest payable | 149 | 195 |
| Other | 1,873 | 1,604 |
| **Total current liabilities** | **5,954** | **5,643** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 14,701 | 14,700 |
| Regulatory liabilities | 6,307 | 6,290 |
| Pension and other postretirement benefits | 2,465 | 2,477 |
| Asset retirement obligations | 3,595 | 3,575 |
| Deferred income taxes | 8,885 | 8,773 |
| Other | 2,266 | 2,178 |
| **Total noncurrent liabilities** | **38,219** | **37,993** |
| **Commitments and Contingencies (Note 9)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 6,613 | 6,514 |
| Reinvested earnings | 7,952 | 8,130 |
| Accumulated other comprehensive income | 5 | 5 |
| **Total shareholders' equity** | **16,150** | **16,229** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 60,323** | **$ 59,865** |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | **(Unaudited)** | |
|---|---|---|
| | **Three Months Ended March 31,** | |
| **(in millions)** | **2015** | **2014** |
| **Cash Flows from Operating Activities** | | |
| Net income | $ 4 | $ 228 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 631 | 538 |
| Allowance for equity funds used during construction | (28) | (22) |
| Deferred income taxes and tax credits, net | 112 | (19) |
| Disallowed capital expenditures | 53 | - |
| Other | 45 | 39 |
| Effect of changes in operating assets and liabilities: | | |

| | | |
|---|---|---|
| Accounts receivable | 215 | 312 |
| Inventories | 58 | 62 |
| Accounts payable | 26 | 53 |
| Income taxes receivable/payable | 2 | (25) |
| Other current assets and liabilities | (123) | 26 |
| Regulatory assets, liabilities, and balancing accounts, net | 195 | (376) |
| Other noncurrent assets and liabilities | (89) | (37) |
| **Net cash provided by operating activities** | **1,101** | **779** |
| **Cash Flows from Investing Activities** | | |
| Capital expenditures | (1,191) | (1,197) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 417 | 530 |
| Purchases of nuclear decommissioning trust investments | (505) | (536) |
| Other | 7 | 11 |
| **Net cash used in investing activities** | **(1,272)** | **(1,192)** |
| **Cash Flows from Financing Activities** | | |
| Net issuances (repayments) of commercial paper, net of discount of $0 and $1 at respective dates | 223 | (33) |
| Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $10 in 2014 | - | 890 |
| Repayments of long-term debt | - | (539) |
| Preferred stock dividends paid | (3) | (3) |
| Common stock dividends paid | (179) | (179) |
| Equity contribution from PG&E Corporation | 100 | 250 |
| Other | 25 | 30 |
| **Net cash provided by financing activities** | **166** | **416** |
| **Net change in cash and cash equivalents** | **(5)** | **3** |
| **Cash and cash equivalents at January 1** | **55** | **65** |
| **Cash and cash equivalents at March 31** | **$ 50** | **$ 68** |
| **Supplemental disclosures of cash flow information** | | |
| Cash received (paid) for: | | |
| Interest, net of amounts capitalized | $ (211) | $ (188) |
| Income taxes, net | - | 1 |
| **Supplemental disclosures of noncash investing and financing activities** | | |
| Capital expenditures financed through accounts payable | $ 217 | $ 171 |

See accompanying Notes to the Condensed Consolidated Financial Statements.



**NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)**

## NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

On April 9, 2015, the CPUC approved final decisions in the three investigations pending against the Utility relating to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion. As a result of the Penalty Decision, the March 31, 2015 Condensed Consolidated Statements of Income reflect total charges of $553 million, consisting of $400 million for a bill credit due to natural gas customers, $100 million of accrued fines payable to the State General Fund (bringing the total accrual for fines payable to $300 million), and $53 million of estimated disallowances related to pipeline safety improvements. (See Note 9 below.)

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility operate in one segment.

The accompanying Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of PG&E Corporation and the Utility's financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 2014 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2014 Form 10-K. This quarterly report should be read in conjunction with the 2014 Form 10-K.

The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

## NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Note 2 of the Notes to the Consolidated Financial Statements in the 2014 Form 10-K.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.



Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at March 31, 2015, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at March 31, 2015, it did not consolidate any of them.

**Pension and Other Postretirement Benefits**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate. Net periodic costs for both are included in Pension Benefits in the table below.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three months ended March 31, 2015 and 2014 were as follows:

| | **Pension Benefits** | | **Other Benefits** | |
|---|---|---|---|---|
| | **Three Months Ended March 31,** | | | |
| **(in millions)** | **2015** | **2014** | **2015** | **2014** |
| Service cost for benefits earned | $ 119 | $ 99 | $ 13 | $ 11 |
| Interest cost | 168 | 173 | 18 | 19 |
| Expected return on plan assets | (218) | (202) | (28) | (26) |
| Amortization of prior service cost | 4 | 5 | 5 | 6 |
| Amortization of net actuarial loss | 3 | - | 1 | - |
| **Net periodic benefit cost** | **76** | **75** | **9** | **10** |
| Regulatory account transfer (1) | 9 | 9 | - | - |
| **Total** | **$ 85** | **$ 84** | **$ 9** | **$ 10** |

(1) The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) are summarized below:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| | Three Months Ended March 31, 2015 | | | |
| Beginning balance | $ (21) | $ 15 | $ 17 | $ 11 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $2, $2, and $0, respectively) [1] | 2 | 3 | - | 5 |
| Amortization of net actuarial loss (net of taxes of $1, $0, and $0, respectively) [1] | 2 | - | - | 2 |
| Regulatory account transfer (net of taxes of $3, $2, and $0, respectively) [1] | (4) | (3) | - | (7) |
| Change in investments (net of taxes of $0, $0, and $12, respectively) | - | - | (17) | (17) |
| **Net current period other comprehensive loss** | **-** | **-** | **(17)** | **(17)** |
| **Ending balance** | **$ (21)** | **$ 15** | **$ -** | **$ (6)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| | Three Months Ended March 31, 2014 | | | |
| Beginning balance | $ (7) | 15 | 42 | 50 |
| **Other comprehensive income before reclassifications:** | | | | |
| Change in investments (net of taxes of $0, $0, and $4, respectively) | - | - | 5 | 5 |
| **Amounts reclassified from other comprehensive income:** [1] | | | | |
| Amortization of prior service cost (net of taxes of $2, $2, and $0, respectively) | 3 | 4 | - | 7 |
| Regulatory account transfer (net of taxes of $2, $2, and $0, respectively) | (3) | (4) | - | (7) |
| **Net current period other comprehensive income** | **-** | **-** | **5** | **5** |
| **Ending balance** | **$ (7)** | **$ 15** | **$ 47** | **$ 55** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above, with the exception of other investments which are held by PG&E Corporation.



**Accounting Standards Issued But Not Yet Adopted**

***Presentation of Debt Issuance Costs***

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,* which amends existing presentation of debt issuance costs. PG&E Corporation and the Utility currently disclose debt issuance costs in current assets - other and noncurrent assets - other. The amendments in this Accounting Standard Update, effective on January 1, 2016, require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility will adopt this standard starting in the first quarter of 2016.

***Accounting for Fees Paid in a Cloud Computing Arrangement***

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update No. 2015-05, *Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement,* which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. The accounting standards update will be effective on January 1, 2016. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

***Revenue Recognition Standard***

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers*, which amends existing revenue recognition guidance. The accounting standards update will be effective on January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

**NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS**

**Regulatory Assets**

Long-term regulatory assets are composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2015** | **December 31, 2014** |
| Pension benefits | $ 2,332 | $ 2,347 |
| Deferred income taxes | 2,521 | 2,390 |
| Environmental compliance costs | 674 | 717 |
| Utility retained generation | 446 | 456 |
| Price risk management | 170 | 127 |
| Unamortized loss, net of gain, on reacquired debt | 108 | 113 |
| Electromechanical meters | 53 | 70 |
| Other | 108 | 102 |
| **Total long-term regulatory assets** | **$ 6,412** | **$ 6,322** |



**Regulatory Liabilities**

Long-term regulatory liabilities are composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2015** | **December 31, 2014** |
| Cost of removal obligations | $ 4,307 | $ 4,211 |
| Recoveries in excess of asset retirement obligations | 760 | 754 |
| Public purpose programs | 743 | 701 |
| Other | 497 | 624 |
| **Total long-term regulatory liabilities** | **$ 6,307** | **$ 6,290** |

**Regulatory Balancing Accounts**

The Utility's recovery of revenue requirements and costs is generally decoupled from the volume of sales. The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets - regulatory assets or noncurrent liabilities - regulatory liabilities, respectively, in the Condensed Consolidated Balance Sheets. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are composed of the following:

| | **Receivable Balance at** | |
|---|---|---|
| **(in millions)** | **March 31, 2015** | **December 31, 2014** |
| Electric distribution | $ 643 | $ 344 |
| Utility generation | 434 | 261 |
| Gas distribution | 413 | 566 |
| Energy procurement | 412 | 608 |
| Public purpose programs | 87 | 109 |
| Other | 238 | 378 |
| **Total regulatory balancing accounts receivable** | **$ 2,227** | **$ 2,266** |

| | **Payable Balance at** | |
|---|---|---|
| **(in millions)** | **March 31, 2015** | **December 31, 2014** |
| Energy procurement | $ 217 | $ 188 |
| Public purpose programs | 144 | 154 |
| Other [1] | 678 | 748 |
| **Total regulatory balancing accounts payable** | **$ 1,039** | **$ 1,090** |

[1] At March 31, 2015 Other regulatory balancing accounts payable mostly includes energy supplier settlements related to the Utility's outstanding bankruptcy claims. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 9 below).

**NOTE 4: DEBT**

**Revolving Credit Facilities and Commercial Paper Program**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at March 31, 2015:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2019 | $ 300 (1) | $ - | $ - | $ 300 |
| Utility | April 2019 | 3,000 (2) | 33 | 556 | 2,411 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 33** | **$ 556** | **$ 2,711** |

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for "swingline" loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for swingline loans.

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $1.75 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities.

On April 27, 2015, PG&E Corporation and the Utility amended and restated their respective $300 million and $3.0 billion revolving credit facilities that were entered into on April 1, 2013. The amendments and restatements extended the termination dates of the credit facilities from April 1, 2019 to April 27, 2020, reduced the amount of lender commitments to the letter of credit sublimits from $100 million to $50 million for PG&E Corporation's credit facility and from $1.0 billion to $500 million for the Utility's credit facility, and reduced the swingline commitment on the Utility's credit facility from $300 million to $75 million.

Borrowings under each amended and restated credit agreement (other than swing line loans) will bear interest based, at each borrower's election, on (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The applicable margin for LIBOR loans will range between 0.9% and 1.475% under PG&E Corporation's amended and restated credit agreement and between 0.8% and 1.275% under the Utility's amended and restated credit agreement.  The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation's amended and restated credit agreement and between 0% and 0.275% under the Utility's amended and restated credit agreement. In addition, the facility fee under PG&E Corporation's and the Utility's amended and restated credit agreements will range between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

**Pollution Control Bonds**

At March 31, 2015, the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.01% to 0.02%. At March 31, 2015, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.01% to 0.03%.

**NOTE 5: EQUITY**

PG&E Corporation's and the Utility's changes in equity for the three months ended March 31, 2015 were as follows:

| (in millions) | PG&E Corporation Total Equity | Utility Total Shareholders' Equity |
|---|---|---|
| **Balance at December 31, 2014** | **$ 16,000** | **$ 16,229** |
| Comprehensive income | 17 | 4 |
| Equity contributions | - | 100 |
| Common stock issued | 156 | - |
| Share-based compensation | 6 | (1) |
| Common stock dividends declared | (221) | (179) |
| Preferred stock dividend requirement | - | (3) |
| Preferred stock dividend requirement of subsidiary | (3) | - |
| **Balance at March 31, 2015** | **$ 15,955** | **$ 16,150** |

In February 2015, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $500 million. During the three months ended March 31, 2015, PG&E Corporation sold 1.4 million shares under the February 2015 equity distribution agreement for cash proceeds of $74 million, net of commissions paid of $1 million.

In addition, PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the three months ended March 31, 2015,
2.2 million shares were issued for cash proceeds of $77 million under these plans.

**NOTE 6: EARNINGS PER SHARE**

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS:

| | Three Months Ended March 31, | |
|---|---|---|
| **(in millions, except per share amounts)** | **2015** | **2014** |
| **Income available for common shareholders** | $ 31 | $ 227 |
| **Weighted average common shares outstanding, basic** | 477 | 459 |
| Add incremental shares from assumed conversions: | | |
| Employee share-based compensation | 4 | 1 |
| **Weighted average common shares outstanding, diluted** | 481 | 460 |
| **Total earnings per common share, diluted** | **$ 0.06** | **$ 0.49** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

## NOTE 7: DERIVATIVES

### Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include forward contracts, swaps, futures, options, and CRRs.



These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Condensed Consolidated Balance Sheets. The Utility expects to fully recover in rates all costs related to derivatives as long as the current ratemaking mechanism remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

Cash collateral paid or received is offset against the fair value of derivative instruments executed with the same counterparty under a master netting arrangement, where the right of offset and the intention to offset exist. Derivatives are presented in the Utility's Condensed Consolidated Balance Sheets on a net basis.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. The fair value of these items is not reflected in the Condensed Consolidated Balance Sheets at fair value, eligible derivatives are accounted for under the accrual method of accounting.

### Volume of Derivative Activity

The volumes of the Utility's outstanding derivatives were as follows:

| | | Contract Volume at | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **March 31, 2015** | **December 31, 2014** |
| Natural Gas [1] (MMBtus [2]) | Forwards and Swaps | 286,357,249 | 308,130,101 |
| | Options | 120,616,913 | 164,418,002 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 5,254,402 | 5,346,787 |
| | Congestion Revenue Rights [3] | 213,503,515 | 224,124,341 |

[1] Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[2] Million British Thermal Units.
[3] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges based on demand when there is insufficient transmission capacity.

**Presentation of Derivative Instruments in the Financial Statements**

At March 31, 2015, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| (in millions) | Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
| Current assets - other | $ 72 | $ (3) | $ 17 | $ 86 |
| Other noncurrent assets - other | 168 | (5) | - | 163 |
| Current liabilities - other | (84) | 3 | 33 | (48) |
| Noncurrent liabilities - other | (175) | 5 | 29 | (141) |
| **Net commodity risk** | **$ (19)** | **$ -** | **$ 79** | **$ 60** |



At December 31, 2014, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| (in millions) | Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
| Current assets - other | $ 73 | (4) | 19 | $ 88 |
| Other noncurrent assets - other | 178 | (13) | - | 165 |
| Current liabilities - other | (78) | 4 | 26 | (48) |
| Noncurrent liabilities - other | (140) | 13 | 9 | (118) |
| **Net commodity risk** | **$ 33** | **$ -** | **$ 54** | **$ 87** |

Gains and losses associated with price risk management activities were recorded as follows:

| | Commodity Risk | |
|---|---|---|
| | Three Months Ended March 31, | |
| (in millions) | 2015 | 2014 |
| Net unrealized gain (loss) - regulatory assets and liabilities [1] | $ (52) | $ 58 |
| Realized loss - cost of electricity [2] | (7) | (18) |
| Realized loss - cost of natural gas [2] | (1) | - |
| **Total commodity risk** | **$ (60)** | **$ 40** |

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Condensed Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
[2] These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Condensed Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At March 31, 2015, the Utility's credit rating was investment

grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| | Balance at | |
|---|---|---|
| (in millions) | March 31, 2015 | December 31, 2014 |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (2) | $ (47) |
| Collateral posting in the normal course of business related to these derivatives | - | 44 |
| **Net position of derivative contracts/additional collateral posting requirements [1]** | **$ (2)** | **$ (3)** |

[1] This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.



## NOTE 8: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 -** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 -** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 -** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts and other investments are held by PG&E Corporation and not the Utility):

| | **Fair Value Measurements** | | | | |
|---|---|---|---|---|---|
| | **At March 31, 2015** | | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Netting [1]** | **Total** |
| **Assets:** | | | | | |
| Money market investments | $ 96 | $ - | $ - | $ - | **$ 96** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 29 | - | - | - | **29** |
| Global equity securities | 1,619 | 13 | - | - | **1,632** |
| Fixed-income securities | 673 | 539 | - | - | **1,212** |
| Total nuclear decommissioning trusts [2] | **2,321** | **552** | **-** | **-** | **2,873** |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | - | 7 | 230 | 9 | **246** |
| Gas | 2 | 1 | - | - | **3** |
| Total price risk management instruments | **2** | **8** | **230** | **9** | **249** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 42 | - | - | **42** |
| Life insurance contracts | - | 74 | - | - | **74** |
| Total rabbi trusts | **-** | **116** | **-** | **-** | **116** |
| Long-term disability trust | | | | | |
| Money market investments | 4 | - | - | - | **4** |
| Global equity securities | - | 24 | - | - | **24** |
| Fixed-income securities | - | 123 | - | - | **123** |
| Total long-term disability trust | **4** | **147** | **-** | **-** | **151** |
| **Total assets** | **$ 2,423** | **$ 823** | **$ 230** | **$ 9** | **$ 3,485** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | $ 59 | $ 11 | $ 188 | $ (70) | **$ 188** |
| Gas | - | 1 | - | - | **1** |
| **Total liabilities** | **$ 59** | **$ 12** | **$ 188** | **$ (70)** | **$ 189** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $347 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2014 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Money market investments | $ 94 | $ - | $ - | $ - | $ **94** |
| Nuclear decommissioning trusts | | | | | |
| Money market investments | 17 | - | - | - | **17** |
| Global equity securities | 1,585 | 13 | - | - | **1,598** |
| Fixed-income securities | 741 | 389 | - | - | **1,130** |
| Total nuclear decommissioning trusts [2] | **2,343** | **402** | **-** | **-** | **2,745** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | - | 17 | 232 | 2 | **251** |
| Gas | 1 | 1 | - | - | **2** |
| Total price risk management instruments | **1** | **18** | **232** | **2** | **253** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 42 | - | - | **42** |
| Life insurance contracts | - | 72 | - | - | **72** |
| Total rabbi trusts | **-** | **114** | **-** | **-** | **114** |
| Long-term disability trust | | | | | |
| Money market investments | 7 | - | - | - | **7** |
| Global equity securities | - | 25 | - | - | **25** |
| Fixed-income securities | - | 128 | - | - | **128** |
| Total long-term disability trust | **7** | **153** | **-** | **-** | **160** |
| Other investments | 33 | - | - | - | **33** |
| **Total assets** | **$ 2,478** | **$ 687** | **$ 232** | **$ 2** | **$ 3,399** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 47 | $ 5 | $ 163 | $ (52) | $ **163** |
| Gas | - | 3 | - | - | **3** |
| **Total liabilities** | **$ 47** | **$ 8** | **$ 163** | **$ (52)** | **$ 166** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $324 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. Investments, primarily consisting of equity securities, that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the three months ended March 31, 2015 and 2014.



***Trust Assets***

Nuclear decommissioning trust assets and other trust assets are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1. Equity securities also include commingled funds that are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world. Investments in these funds are classified as Level 2 because price quotes are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are classified as Level 3 and are valued based on CRR auction prices, including historical prices. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Risk Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.



Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 7 above.)

| **(in millions)** | **Fair Value at March 31, 2015** | | **Valuation** | **Unobservable** | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Technique** | **Input** | **Range** [(1)] |
| Congestion revenue rights | $ 230 | $ 64 | Market approach | CRR auction prices | $ (15.97) - 8.17 |
| Power purchase agreements | $ - | $ 124 | Discounted cash flow | Forward prices | $ 15.56 - 47.26 |

(1) Represents price per megawatt-hour

| **(in millions)** | **Fair Value at December 31, 2014** | | **Valuation** | **Unobservable** | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Technique** | **Input** | **Range** [(1)] |
| Congestion revenue rights | $ 232 | $ 63 | Market approach | CRR auction prices | $ (15.97) - 8.17 |
| Power purchase agreements | $ - | $ 100 | Discounted cash flow | Forward prices | $ 16.04 - 56.21 |

(1) Represents price per megawatt-hour

**Level 3 Reconciliation**

The following tables present the reconciliation for Level 3 price risk management instruments for the three months ended March 31, 2015 and 2014:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2015** | **2014** |
| Asset (liability) balance as of January 1 | **$ 69** | **$ (30)** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | (27) | 8 |
| **Asset (liability) balance as of March 31** | **$ 42** | **$ (22)** |

[1] The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at March 31, 2015 and December 31, 2014, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at March 31, 2015 and December 31, 2014.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At March 31, 2015 | | At December 31, 2014 | |
|---|---|---|---|---|
| **(in millions)** | **Carrying Amount** | **Level 2 Fair Value** | **Carrying Amount** | **Level 2 Fair Value** |
| PG&E Corporation | $ 350 | $ 354 | $ 350 | $ 352 |
| Utility | 13,779 | 16,324 | 13,778 | 15,851 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| **As of March 31, 2015** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 29 | $ - | $ - | $ 29 |
| Global Equity securities | 536 | 1,109 | (13) | 1,632 |
| Fixed Income securities | 1,133 | 82 | (3) | 1,212 |
| Total nuclear decommissioning trusts [(1)] | 1,698 | 1,191 | (16) | 2,873 |
| **Total** | **$ 1,698** | **$ 1,191** | **$ (16)** | **$ 2,873** |
| **As of December 31, 2014** | | | | |
| Nuclear decommissioning trusts | | | | |
| Money market investments | $ 17 | $ - | $ - | $ 17 |
| Global Equity securities | 520 | 1,087 | (9) | 1,598 |
| Fixed-income securities | 1,059 | 75 | (4) | 1,130 |
| Total nuclear decommissioning trusts [(1)] | 1,596 | 1,162 | (13) | 2,745 |
| Other investments | 5 | 28 | - | 33 |
| **Total** | **$ 1,601** | **$ 1,190** | **$ (13)** | **$ 2,778** |

[(1)] Represents amounts before deducting $347 million and $324 million at March 31, 2015 and December 31, 2014, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

| (in millions) | As of March 31, 2015 |
|---|---|
| Less than 1 year | $ 25 |
| 1-5 years | 450 |
| 5-10 years | 257 |
| More than 10 years | 480 |
| **Total maturities of debt securities** | **$ 1,212** |

The following table provides a summary of activity for the debt and equity securities:

| | Three Months Ended | |
|---|---|---|
| (in millions) | March 31, 2015 | March 31, 2014 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 417 | $ 530 |
| Gross realized gains on sales of securities held as available-for-sale | 35 | 56 |
| Gross realized losses on sales of securities held as available-for-sale | (3) | (1) |

**NOTE 9: CONTINGENCIES AND COMMITMENTS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters.

**Enforcement and Litigation Matters**

***CPUC Investigations Related to Natural Gas Transmission***

On April 9, 2015, the CPUC approved final decisions in the three investigations pending against the Utility relating to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision which imposes penalties on the Utility totaling $1.6 billion (the "Penalty Decision"). The Utility has elected not to appeal any of the decisions.

The penalties, to be funded by shareholders, are comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. The Penalty Decision requires that at least $688.5 million of the $850 million be allocated to capital expenditures and that the Utility be precluded from including these capital costs in rate base. The remainder will be allocated to safety-related expenses. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent.

For the three months ended March 31, 2015, the Utility recorded additional charges of $553 million as a result of the Penalty Decision. The cumulative charges at March 31, 2015, and the anticipated future financial impact are shown in the following table:

| (in millions) | Three Months Ended March 31, 2015 | Cumulative Charges March 31, 2015 | Anticipated Future Financial Impact | Total Amount |
|---|---|---|---|---|
| Fine payable to the state [1] | $ 100 | $ 300 | $ - | $ 300 |
| Customer bill credit | 400 | 400 | - | 400 |
| Charge for disallowed capital [2] | 53 | 53 | 636 | 689 |
| Disallowed revenue for pipeline safety expenses [3] | - | - | 161 | 161 |
| CPUC estimated cost of other remedies [4] | - | 20 | 30 | 50 |
| **Total Penalty Decision fines and remedies recorded** | **$ 553** | **$ 773** | **$ 827** | **$ 1,600** |

(1) The Utility increased its accrual from $200 million at December 31, 2014 to $300 million at March 31, 2015.

(2) The Penalty Decision prohibits the Utility from recovering certain expenses and capital spending associated with pipeline safety-related projects and programs that the CPUC will identify in the final decision to be issued in the Utility's 2015 GT&S rate case. The Utility estimates that approximately $53 million of capital spending in the three months ended March 31, 2015, is probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.

(3) These costs are being expensed as incurred. Future GT&S revenues will be reduced for these unrecovered expenses.

(4) In the Penalty Decision, the CPUC estimates that the Utility would incur $50 million to comply with the other remedies in the Penalty Decision, including $30 million to reimburse the CPUC for the costs of future audits. Remedial costs are expensed as incurred. Other than the refund of CPUC audit costs, the majority of the remedies have been completed or are underway and the associated costs have already been incurred.

At March 31, 2015, the Condensed Consolidated Balance Sheets include $300 million in other current liabilities for the fines payable, and $400 million in current regulatory liabilities for the one-time bill credit due to the Utility's natural gas customers. The charges recorded are reflected in operating and maintenance expenses in the March 31, 2015, Condensed Consolidated Statements of Income. It is uncertain what costs the CPUC will ultimately count towards the $850 million shareholder-funded obligation. To the extent the Utility's actual costs exceed qualified amounts and are not authorized for recovery, the Utility may be required to record additional charges in future periods.

***Improper CPUC Communications***

In the Penalty Decision (discussed above), the CPUC stated that it will begin a new investigation to examine allegations by the City of San Bruno that communications between the Utility's employees and CPUC personnel violated the CPUC's rules relating to ex parte communications. Ex parte communications include any communication between a decision maker and an interested person concerning substantive issues in certain identified categories of formal proceedings before the CPUC. The Utility believes that the communications cited by San Bruno are not prohibited ex parte communications. If the CPUC determines that the communications constitute ex parte violations, it is reasonably possible that the CPUC will impose penalties or other remedies, but the Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties.

The Utility also notified the CPUC of ex parte communications between the Utility and the CPUC regarding the 2015 GT&S rate case. In November 2014, the CPUC imposed a fine of $1.05 million on the Utility for these communications. (The ORA, TURN, and the City of San Bruno have asked the CPUC to reconsider its decision contending that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million.) In addition, the CPUC disallowed the Utility from recovering up to the entire amount of the revenue increase that may be authorized in the GT&S rate case and that otherwise would have been collected from ratepayers over a five-month period. The Utility has asked the CPUC to reconsider its decision. The exact amount of any revenue disallowance will be determined in the CPUC's final decision in the GT&S rate case that is scheduled to be issued in August 2015.

The Utility also notified the CPUC of additional email communications between the Utility and the CPUC regarding various matters (not limited to the GT&S rate case) that the Utility believes may constitute or describe ex parte communications. For these additional communications, the Utility believes it is probable that CPUC enforcement action will be taken. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties.



***Other CPUC Matters***

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices for its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014. On April 10, 2015, the assigned Commissioner issued a scoping memo and ruling stating that the scope of the proceeding is whether or not the Utility violated any applicable laws, rules, or regulations "by its record-keeping policies and practices with respect to maintaining safe operation of its gas distribution system." The scope of the proceeding also may include matters resulting from the SED's ongoing reviews of the Utility's record-keeping practices relating to mapping, pre-excavation location and marking, and pressure validation for distribution facilities, among other issues.

The procedural schedule requires the SED's and intervenors' testimony to be submitted starting in September 2015 with the Utility's response due in November 2015 followed by rebuttal testimony in December 2015. Hearings are scheduled for January 19-22, 2016.

PG&E Corporation and the Utility believe it is reasonably possible that the CPUC will impose penalties on the Utility or require the Utility to implement operational remedies. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining penalties. In addition, the Utility could incur material costs to implement operational remedies, which may not be recoverable.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

*Potential Safety Citations*

The SED periodically audits utility operating practices, conducts investigations of potential violations, and has authority to issue citations and impose fines on the utilities for violations of applicable laws and regulations. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken.

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations identified through the Utility's self-reports, SED investigations and audits. The Utility believes it is probable that the SED will impose fines or take other enforcement action based on some of the Utility's remaining self-reports or based on allegations contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

### *Federal and State Matters*

*Federal Criminal Indictment*

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also seeks an alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment.

The trial is set to begin March 8, 2016. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Condensed Consolidated Financial Statements as such amounts are not considered to be probable.

*Other Federal and State Matters*

The U.S. Attorney's Office in San Francisco and the California Attorney General's office have also begun investigations in connection with the ex parte communications (see "Improper CPUC Communications" above). The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility. In addition, the Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. (For more information refer to Note 14 of the Notes to the Consolidated Financial Statements appearing under Item 8 in the 2014 Annual Report on Form 10-K). It is uncertain whether any charges will be brought against the Utility. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case.

### Capital Expenditures relating to Pipeline Safety Enhancement Plan

At March 31, 2015, approximately $600 million of PSEP-related capital costs is recorded in property, plant, and equipment on the Condensed Consolidated Balance Sheets. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

### Other Legal and Regulatory Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to the enforcement and litigation matters described above) totaled $39 million at March 31, 2015, and $55 million at December 31, 2014. These amounts are included in other current liabilities in the Condensed Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Environmental Remediation Contingencies**

The Utility's environmental remediation liability is primarily included in non-current liabilities on the Condensed Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2015** | **December 31, 2014** |
| Topock natural gas compressor station [1] | $ 298 | $ 291 |
| Hinkley natural gas compressor station [1] | 153 | 158 |
| Former manufactured gas plant sites owned by the Utility or third parties | 257 | 257 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites | 159 | 150 |
| Fossil fuel-fired generation facilities and sites | 98 | 98 |
| **Total environmental remediation liability** | **$ 965** | **$ 954** |

[1] See "Natural Gas Compressor Station Sites" below.

At March 31, 2015 the Utility expected to recover $677 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility will also incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

***Natural Gas Compressor Station Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as the "Topock site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

***Hinkley Site***

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. On January 22, 2015, the Regional Board issued a preliminary draft clean-up and abatement order that proposes that the Utility continue and improve its remedial treatment methods evaluated in the environmental report, along with a proposed monitoring and reporting program and proposed deadlines in 2021 and 2026 to meet specified interim clean-up targets. The Regional Board is tentatively scheduled to consider final adoption of the clean-up and abatement order at its September 2015 meeting.

The Utility's environmental remediation liability at March 31, 2015 reflects the Utility's best estimate of probable future costs associated with its final remediation plan and interim remediation measures. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, and the nature and extent of the chromium contamination. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

*Topock Site*

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. In September 2014, the Utility submitted its 90% remedial design plan to regulatory authorities and expects to submit its final remedial design plan in mid-2015, which would seek approval to begin construction of an in-situ groundwater treatment system that will convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River. The Utility's environmental remediation liability at March 31, 2015 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

***Reasonably Possible Environmental Contingencies***

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.8 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations during the period in which they are recorded.

**Resolution of Remaining Chapter 11 Disputed Claims**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers.

At December 31, 2014, the Consolidated Balance Sheets reflected $434 million in net claims, within Disputed claims and customer refunds, and $291 million of cash in escrow for payment of the remaining net disputed claims, within Restricted cash. There were no significant changes to these balances during the three months ended March 31, 2015.

**Tax Matters**

The IRS is currently reviewing several matters in the 2011, 2012, and 2013 tax returns. The most significant relates to a 2011 accounting method change to adopt guidance issued by the IRS in determining which repair costs are deductible for the electric transmission and distribution businesses. PG&E Corporation and the Utility expect that the IRS will complete its review of the deductible repair costs for the electric transmission and distribution businesses in 2015. The IRS is also expected to issue guidance during 2015 that determines which repair costs are deductible for the natural gas transmission and distribution businesses. PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the IRS guidance that is issued and the resolution of the audits related to the 2011, 2012, and 2013 tax returns. As of March 31, 2015, it is reasonably possible that unrecognized tax benefits will decrease by approximately $370 million within the next 12 months, and most of this decrease would not impact net income.

There were no other significant developments to tax matters during the three months ended March 31, 2015. (Refer to Note 8 of the Notes to the Consolidated Financial Statements in Item 8 of the 2014 Form 10-K.)

**Purchase Commitments**

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. The Utility disclosed its commitments at December 31, 2014 in Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2014 Form 10-K. The Utility has not entered into any new material commitments during the three months ended March 31, 2015.



## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

**OVERVIEW**

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. It should also be read in conjunction with the 2014 Form 10-K.

On April 9, 2015, the CPUC approved final decisions in the three investigations pending against the Utility relating to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion. The penalties, to be funded by shareholders, are comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. PG&E Corporation's and the Utility's financial results for the three months ended March 31, 2015, reflect various charges associated with the Penalty Decision as discussed below.



**Summary of Changes in Net Income and Earnings per Share**

PG&E Corporation's financial results for the three months ended March 31, 2015 reflect an increase in the Utility's revenues, as authorized in the CPUC's final decision issued in the Utility's 2014 GRC on August 14, 2014 and various changes associated with the Penalty Decision issued on April 9, 2015.

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS compared to the same period in the prior year (see "Results of Operations" below for additional information):

| (in millions, except per share amounts) | Earnings | EPS (Diluted) |
|---|---|---|
| **Income Available for Common Shareholders - March 31, 2014** | $ 227 | $ 0.49 |
| 2014 GRC cost recovery [1] | 99 | 0.21 |
| Growth in rate base earnings [2] | 26 | 0.05 |
| Nuclear refueling outage | 26 | 0.05 |
| Timing of taxes [3] | 20 | 0.04 |
| Gain on disposition of SolarCity stock | 14 | 0.03 |
| Fines and penalties [4] | (369) | (0.77) |
| Timing of 2015 GT&S cost recovery [5] | (36) | (0.08) |
| Increase in shares outstanding [6] | - | (0.02) |
| Other | 24 | 0.06 |
| **Income Available for Common Shareholders - March 31, 2015** | **$ 31** | **$ 0.06** |

[1] Represents the increase in base revenues authorized by the CPUC in the 2014 GRC decision for the three months ended March 31, 2015, including the impact of flow-through ratemaking treatment for federal tax deductions for repairs. In 2013, the Utility incurred approximately $200 million of expense and $1 billion of capital costs above authorized levels. The 2014 GRC decision authorized revenues that support this higher level of spending during 2014 and throughout the GRC period. The increase in revenue related to 2014 was not recognized until the quarter ended September 30, 2014, when the 2014 GRC decision was issued.

[2] Represents the impact of the increase in rate base as authorized in various rate cases during the three months ended March 31, 2015 as compared to the same period in 2014.

[3] Represents the timing of taxes reportable in quarterly financial statements.

[4] Represents the impact during the three months ended March 31, 2015 of the Penalty Decision issued on April 9, 2015. See "Enforcement and Litigation Matters" below.

[5] Represents expenses during the three months ended March 31, 2015 requested in the GT&S rate case with no corresponding increase in revenue. The Utility's 2015 GT&S request to increase revenues is pending a CPUC decision. After a final decision is issued, the Utility will be authorized to collect any increase in revenue requirements from January 1, 2015.

[6] Represents the impact of a higher number of weighted average shares of common stock outstanding during the three months ended March 31, 2015 as compared to the same periods in 2014. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including unrecovered expenses.

**Key Factors Affecting Financial Results**

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materially affected by the following factors:

- *Penalties, Fines and Remedial Costs.* Future financial results will be impacted by the timing and amount of costs the Utility incurs for designated pipeline safety projects and programs and to implement remedial measures, as required by the Penalty Decision. The Utility also could incur fines associated with pending federal criminal charges that the Utility knowingly and willfully violated the Pipeline Safety Act and illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. Based on the superseding indictment's allegations, the maximum statutory fine would be $14 million and the maximum alternative fine would be approximately $1.13 billion. Federal and state authorities also are conducting investigations in connection with certain communications between the Utility and CPUC personnel. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case. Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to these and other enforcement matters, including new CPUC investigations. (See "Enforcement and Litigation Matters" below.)

- *The Timing and Outcome of Ratemaking Proceedings*. In the GT&S rate case, the Utility has requested that the CPUC authorize revenue requirements for the Utility's gas transmission and storage operations from 2015 through 2017. The Utility has requested an increase in its 2015 revenue requirements of $555 million over the comparable authorized revenues, as well as increases for 2016 and 2017. In response to the Utility's violations of the CPUC's rules regarding ex parte communications relating to the 2015 GT&S rate case, the CPUC issued a decision to disallow up to five months of the GT&S incremental revenues that would otherwise be authorized in the final decision, which is scheduled to be issued in August 2015. The Utility and other parties have filed applications requesting the CPUC to reconsider this decision. It is uncertain whether this decision will be upheld and what amount of GT&S revenue requirements will ultimately be authorized. In addition, the Utility has a TO rate case pending at the FERC. The outcome of ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* Whether the Utility is able to earn its authorized rate of return could be materially affected if the Utility's actual costs differ from the amounts that have been authorized in the final 2014 GRC decision and that may be authorized in the 2015 GT&S rate case and future rate case decisions. In addition to incurring shareholder-funded costs and costs associated with remedial measures required by the Penalty Decision, the Utility forecasts that in 2015 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million, including costs to identify and remove encroachments from transmission pipeline rights-of-way to perform and to perform continuing work under the Utility's PSEP. Actual costs could be higher. The ultimate amount of unrecovered costs also could be affected by how the CPUC determines which costs are included in calculating whether the $850 million shareholder-funded obligation under the Penalty Decision has been met, and the outcome of pending and future investigations and enforcement matters. (See "Enforcement and Litigation Matters" below.)

- *The Amount and Timing of the Utility's Financing Needs*. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. For the three months ended March 31, 2015, PG&E Corporation issued $151 million of common stock and made equity contributions to the Utility of $100 million. PG&E Corporation forecasts that it will continue issuing a material amount of equity to support the Utility's capital expenditures and to fund unrecovered pipeline-related costs (including costs incurred under the Penalty Decision) and to pay the fine imposed by the Penalty Decision and additional fines and penalties that may be required by the final outcomes of ongoing enforcement matters. These equity issuances would have a further material dilutive effect on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" below, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in the 2014 Form 10-K and in Part II below under "Item 1A. Risk Factors." In addition, this quarterly report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Cautionary Language Regarding Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.



**RESULTS OF OPERATIONS**

**PG&E Corporation**

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The following table provides a summary of net income available for common shareholders for the three months ended March 31, 2015 and 2014:

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| **(in millions)** | **2015** | | **2014** | |
| Consolidated Total | $ | 31 | $ | 227 |
| PG&E Corporation | | 30 | | 2 |
| Utility | $ | 1 | $ | 225 |

PG&E Corporation's net income primarily consists of interest expense on long-term debt, other income from investments, and income taxes. For the three months ended March 31, 2015, results include approximately $30 million of realized gains and associated tax benefits recognized with an investment in SolarCity Corporation with no similar activity during the same period in 2014.

**Utility**

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three months ended March 31, 2015 and 2014. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

The Utility's operating results for the three months ended March 31, 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

| (in millions) | Three Months Ended March 31, 2015 — Revenues and Costs: That Impacted Earnings | That Did Not Impact Earnings | Total Utility | Three Months Ended March 31, 2014 — Revenues and Costs: That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
|---|---|---|---|---|---|---|
| Electric operating revenues | $ 1,786 | $ 1,228 | $ 3,014 | $ 1,589 | $ 1,411 | $ 3,000 |
| Natural gas operating revenues | 506 | 380 | 886 | 471 | 419 | 890 |
| **Total operating revenues** | **2,292** | **1,608** | **3,900** | **2,060** | **1,830** | **3,890** |
| Cost of electricity | - | 1,000 | 1,000 | - | 1,210 | 1,210 |
| Cost of natural gas | - | 274 | 274 | - | 360 | 360 |
| Operating and maintenance | 1,589 | 334 | 1,923 | 1,037 | 260 | 1,297 |
| Depreciation, amortization, and decommissioning | 631 | - | 631 | 538 | - | 538 |
| **Total operating expenses** | **2,220** | **1,608** | **3,828** | **1,575** | **1,830** | **3,405** |
| **Operating income** | **$ 72** | **$ -** | **$ 72** | **$ 485** | **$ -** | **$ 485** |
| Interest income [1] | | | 1 | | | 2 |
| Interest expense [1] | | | (187) | | | (179) |
| Other income, net [1] | | | 26 | | | 20 |
| Income (Loss) before income taxes | | | (88) | | | 328 |
| Income tax provision (benefit) [1] | | | (92) | | | 100 |
| Net income | | | 4 | | | 228 |
| Preferred stock dividend requirement [1] | | | 3 | | | 3 |
| **Income Available for Common Stock** | | | **$ 1** | | | **$ 225** |

[1] These items impacted earnings for the three months ended March 31, 2015 and 2014.

**Utility Revenues and Costs that Impacted Earnings**

The following discussion presents the Utility's operating results for the three months ended March 31, 2015 and 2014, focusing on revenues and expenses that impacted earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased by $232 million or 11% in the three months ended March 31, 2015 compared to the same period in 2014. This increase is primarily due to approximately $250 million of higher base revenues authorized by the CPUC in the 2014 GRC decision and higher TO rate case base revenues. The 2015 GRC revenue increase includes approximately $115 million related to 2014 that was not recognized until the quarter ended September 30, 2014, as a result of the timing of the GRC decision. The increase in operating revenues was offset by the absence of $34 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the three months ended March 31, 2014.

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings increased by $552 million or 53% in the three months ended March 31, 2015 compared to the same period in 2014. The increase is primarily due to the following charges associated with the Penalty Decision:

- a $400 million bill credit to natural gas customers;
- a $100 million increase to the Utility's accrual for fines accrued and payable to the State General Fund (bringing the total amount accrued to $300 million); and,
- a $53 million charge for estimated capital disallowances related to pipeline safety improvements.



The above expenses were partially offset by a $44 million decrease in costs related to a scheduled nuclear refueling outage at Diablo Canyon that occurred during the three months ended March 31, 2014 with no similar outage during the three months ended March 31, 2015.

The Utility's future financial statements will be impacted by unrecoverable pipeline-related expenses as well as disallowed revenues and additional charges associated with the Penalty Decision. (See "Key Factors Affecting Financial Results" above and "Enforcement and Litigation Matters" below.)

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased $93 million or 17% in the three months ended March 31, 2015 compared to the same period in 2014, primarily due to an increase in depreciation rates as authorized by the CPUC in the 2014 GRC decision and an increase in capital additions.

*Interest Income, Interest Expense, and Other Income, Net*

There were no material changes to interest income, interest expense, and other income, net for the periods presented.

*Income Tax Provision*

The Utility's revenue requirements for 2014 through 2016, as authorized in the 2014 GRC decision, reflect flow-through ratemaking for income tax expense benefits attributable to the accelerated recognition of repair costs and certain other property-related costs for federal tax purposes. The Utility's financial results reflect a reduction in income tax expense associated with these temporary differences, resulting in a lower effective tax rate. (See Note 8 of the Notes to the Consolidated Financial Statements in Item 8 of the 2014 Form 10-K.)

Additionally, for the three months ended March 31, 2015, the Utility recorded charges totaling $553 million (including $100 million that is not tax deductible) as a result of the Penalty Decision. Under applicable accounting standards, the tax effect of these charges was recorded at the statutory rate.

The Utility had an income tax benefit of $92 million and an income tax expense of $100 million in the three months ended March 31, 2015 and 2014, respectively. The Utility's effective tax rates were a 105% benefit and a 30% expense in the three months ended March 31, 2015 and 2014, respectively. The change in the effective tax rate was primarily due to the impact of the Penalty Decision, as well as the effects of flow-through ratemaking for income taxes as described above.

**Utility Revenues and Costs that did not Impact Earnings**

*Cost of Electricity*

The Utility's cost of electricity includes the costs of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, emissions costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| **(in millions)** | **2015** | | **2014** | |
| Cost of purchased power | $ | 922 | $ | 1,112 |
| Fuel used in own generation facilities | | 78 | | 98 |
| **Total cost of electricity** | **$** | **1,000** | **$** | **1,210** |
| Average cost of purchased power per kWh [(1)] | $ | 0.099 | $ | 0.089 |
| Total purchased power (in millions of kWh) [(2)] | | 9,291 | | 12,468 |

[(1)] Average cost of purchased power for the three months ended March 31, 2015 increased compared to the same period in 2014 primarily due to higher volume of renewables. This increase was partially offset by lower market prices for natural gas.
[(2)] Total purchased power for the three months ended March 31, 2015 decreased compared to the same period in 2014 primarily due to an increase in the Utility's own generation at Diablo Canyon.



The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities including Diablo Canyon and its hydroelectric plants, and the cost effectiveness of each source of electricity.

*Cost of Natural Gas*

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, emissions costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand. The Utility expects the cost of natural gas for 2015 will continue to be lower due to lower market prices.

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| **(in millions)** | **2015** | | **2014** | |
| Cost of natural gas sold | $ | 235 | $ | 324 |
| Transportation cost of natural gas sold | | 39 | | 36 |
| **Total cost of natural gas** | **$** | **274** | **$** | **360** |

| | | |
|---|---|---|
| Average cost per Mcf [1] of natural gas sold | $ 3.26 | $ 4.15 |
| Total natural gas sold (in millions of Mcf) [1] | 72 | 78 |

[1] One thousand cubic feet

*Operating and Maintenance Expenses*

The Utility's operating expenses also include certain recoverable costs that the Utility incurs as part of its operations such as pension contributions and public purpose programs costs. If the Utility were to spend over authorized amounts, these expenses could have an impact to earnings.

**LIQUIDITY AND FINANCIAL RESOURCES**

**Overview**

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its debt financing costs. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends, primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and borrowings and repayments under its revolving credit facility. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation forecasts that it will issue between $700 million and $800 million in common stock during 2015 primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by unrecovered pipeline-related costs (including costs incurred to comply with the Penalty Decision) and to pay fines imposed by the Penalty Decision and additional fines and penalties that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" below. Common stock issuances by PG&E Corporation to fund these needs would have a material dilutive impact on PG&E Corporation's EPS.



**Cash and Cash Equivalents**

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 9 of the Notes to the Condensed Consolidated Financial Statements). The Utility is uncertain when and how the remaining disputed claims will be resolved.

**Financial Resources**

***Debt and Equity Financings***

PG&E Corporation entered into a new equity distribution agreement in February 2015 providing for the sale of its common stock having an aggregate gross sales price of up to $500 million. During the three months ended March 31, 2015, PG&E Corporation sold 1.4 million shares, under the February 2015 equity distribution agreement for cash proceeds of $74 million, net of commissions paid of $1 million.

In addition, PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the three months ended March 31, 2015, 2.2 million shares were issued for cash proceeds of $77 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility. For the three months ended March 31, 2015, PG&E Corporation made equity contributions to the Utility of $100 million. Additionally, PG&E Corporation and the Utility expect to continue to issue long-term and short-term debt for general corporate purposes and to maintain the CPUC-authorized capital structure during 2015.

***Revolving Credit Facilities and Commercial Paper Program***

At March 31, 2015, PG&E Corporation and the Utility had $300 million and $2.4 billion available under their respective $300 million and $3.0 billion revolving credit facilities. On April 27, 2015, PG&E Corporation and the Utility amended and restated their respective $300 million and $3.0 billion revolving credit facilities that were entered into on April 1, 2013. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements and "Item 5. Other Information")

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, these revolving credit facilities include usual and customary provisions regarding events of default and covenants limiting liens, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. At March 31, 2015, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

***Dividends***

In February 2015, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $218 million, of which approximately $213 million was paid on April 15, 2015 to shareholders of record on March 31, 2015.

In February 2015, the Board of Directors of the Utility declared a common stock dividend of $179 million that was paid to PG&E Corporation on February 19, 2015.

In February 2015, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on May 15, 2015, to shareholders of record on April 30, 2015.

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Three Months Ended March 31, | |
|---|---|---|
| **(in millions)** | **2015** | **2014** |
| Net cash provided by operating activities | $ 1,101 | $ 779 |
| Net cash used in investing activities | (1,272) | (1,192) |
| Net cash provided by financing activities | 166 | 416 |
| **Net increase (decrease) in cash and cash equivalents** | **$ (5)** | **$ 3** |

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During the three months ended March 31, 2015, net cash provided by operating activities increased by $322 million compared to the same period in 2014. This increase was primarily due to higher base revenue collections authorized in the 2014 GRC and lower purchased power costs (see "Cost of Electricity" under "Results of Operations - Utility Revenues and Costs that do not Impact Earnings" above).

Future cash flow from operating activities will be affected by various factors, including:

- the timing of a shareholder-funded bill credit of $400 million to natural gas customers in 2016, and the payment of a $300 million fine to the State General Fund during 2015, as required by the Penalty Decision (see "Enforcement and Litigation Matters" below);
- the timing and amounts of other fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement matters (see "Enforcement and Litigation Matters" below);
- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system (including costs to implement remedial measures and $850 million to pay for designated pipeline safety projects and programs, as required by the Penalty Decision);
- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments; and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

***Investing Activities***

Net cash used in investing activities increased by $80 million during the three months ended March 31, 2015 as compared to the same period in 2014. The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $5.5 billion in capital expenditures in 2015 and between $5.3 billion and $5.8 billion in 2016. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases.



***Financing Activities***

During the three months ended March 31, 2015, net cash provided by financing activities decreased by $250 million compared to the same period in 2014. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on commercial paper and other short-term debt to fund temporary financing needs.



**ENFORCEMENT AND LITIGATION MATTERS**

***CPUC Investigations Related to Natural Gas Transmission***

As described above, the Penalty Decision imposes penalties, to be funded by shareholders, that are comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. The Penalty Decision requires that at least $688.5 million of the $850 million be allocated to capital expenditures and that the Utility be precluded from including these capital costs in rate base. The remainder will be allocated to safety-related expenses. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent.

For the three months ended March 31, 2015, the Utility recorded additional charges of $553 million as a result of the Penalty Decision. The cumulative charges at March 31, 2015, and the anticipated future financial impact are shown in the following table:

| (in millions) | Three Months Ended March 31, 2015 | Cumulative Charges March 31, 2015 | Anticipated Future Financial Impact | Total Amount |
|---|---|---|---|---|
| Fine payable to the state [(1)] | $ 100 | $ 300 | $ - | $ 300 |
| Customer bill credit | 400 | 400 | - | 400 |
| Charge for disallowed capital [(2)] | 53 | 53 | 636 | 689 |
| Disallowed revenue for pipeline safety expenses [(3)] | - | - | 161 | 161 |
| CPUC estimated cost of other remedies [(4)] | - | 20 | 30 | 50 |
| **Total Penalty Decision fines and remedies recorded** | **$ 553** | **$ 773** | **$ 827** | **$ 1,600** |

(1) The Utility increased its accrual from $200 million at December 31, 2014 to $300 million at March 31, 2015.

(2) The Penalty Decision prohibits the Utility from recovering certain expenses and capital spending associated with pipeline safety-related projects and programs that the CPUC will identify in the final decision to be issued in the Utility's 2015 GT&S rate case. The Utility estimates that approximately $53 million of capital spending in the three months ended March 31, 2015, is probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.

(3) These costs are being expensed as incurred. Future GT&S revenues will be reduced for these unrecovered expenses. Management intends to categorize the reduction in revenues in future periods as unrecovered costs for non-GAAP purposes.

(4) In the Penalty Decision, the CPUC estimates that the Utility would incur $50 million to comply with the other remedies in the Penalty Decision, including $30 million to reimburse the CPUC for the costs of future audits. Remedial costs are expensed as incurred. Other than the refund of CPUC audit costs, the majority of the remedies have been completed or are underway and the associated costs have already been incurred.

At March 31, 2015, the Condensed Consolidated Balance Sheets include $300 million in other current liabilities for the fines payable, and $400 million in current regulatory liabilities for the one-time bill credit due to the Utility's natural gas customers. The charges recorded are reflected in operating and maintenance expenses in the March 31, 2015, Condensed Consolidated Statements of Income. It is uncertain what costs the CPUC will ultimately count towards the $850 million shareholder-funded obligation. To the extent the Utility's actual costs exceed qualified amounts and are not authorized for recovery, the Utility may be required to record additional charges in future periods.

***Potential CPUC Investigation of the Utility's Safety Culture***

In connection with the issuance of the Penalty Decision, the President of the CPUC questioned whether the Utility has developed a safety culture that is effective throughout the organization and whether the CPUC's theories of deterrence - its system of penalties and remedies - assure an effective safety culture in a utility. He directed the CPUC to begin a new investigation to examine the Utility's safety culture and practices, including whether they are effective and comprehensive across the organization, and whether there is sufficient accountability for safety results. He also questioned whether the Utility "is too big to succeed" from a safety perspective, although he did not order the CPUC to begin a new investigation into this issue. He stated that he intended to request the CPUC's Legal Division to analyze and evaluate the CPUC's policies regarding penalties and remedies, and make recommendations for adoption by the CPUC.



The timing, scope, and potential outcome of the new investigation and analysis are uncertain.

***Improper CPUC Communications***

In the Penalty Decision (discussed above), the CPUC stated that it will begin a new investigation to examine allegations by the City of San Bruno that communications between the Utility's employees and CPUC personnel violated the CPUC's rules relating to ex parte communications. Ex parte communications include any communication between a decision maker and an interested person concerning substantive issues in certain identified categories of formal proceedings before the CPUC. The Utility believes that the communications cited by San Bruno are not prohibited ex parte communications. If the CPUC determines the communications constitute ex parte violations, it is reasonably possible that it will impose penalties or other remedies, but the Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties.

The Utility also notified the CPUC of ex parte communications between the Utility and the CPUC regarding the 2015 GT&S rate case. In November 2014, the CPUC imposed a fine of $1.05 million on the Utility for these communications. (The ORA, TURN, and the City of San Bruno have asked the CPUC to reconsider its decision contending that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million.) In addition, the CPUC disallowed the Utility from recovering up to the entire amount of the revenue increase that may be authorized in the GT&S rate case and that otherwise would have been collected from ratepayers over a five-month period. The Utility has asked the CPUC to reconsider its decision. The exact amount of any revenue disallowance will be determined in the CPUC's final decision in the GT&S rate case that is scheduled to be issued in August 2015. (See "Ratemaking Proceedings" below.)

The Utility also notified the CPUC of additional email communications between the Utility and the CPUC regarding various matters (not limited to the GT&S rate case) that the Utility believes may constitute or describe ex parte communications. For these additional communications, the Utility believes it is probable that CPUC enforcement action will be taken. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties.

***Other CPUC Matters***

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices for its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014. On April 10, 2015, the assigned Commissioner issued a scoping memo and ruling stating that the scope of the proceeding is whether or not the Utility violated any applicable laws, rules, or regulations "by its record-keeping policies and practices with respect to maintaining safe operation of its gas distribution system." The scope of the proceeding also may include matters resulting from the SED's ongoing reviews of the Utility's record-keeping practices relating to mapping, pre-excavation location and marking, and pressure validation for distribution facilities, among other issues.

The procedural schedule requires the SED's and intervenors' testimony to be submitted starting in September 2015 with the Utility's response due in November 2015 followed by rebuttal testimony in December 2015. Hearings are scheduled for January 19-22, 2016.

PG&E Corporation and the Utility believe it is reasonably possible that the CPUC will impose penalties on the Utility or require the Utility to implement operational remedies. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining penalties. In addition, the Utility could incur material costs to implement operational remedies, which may not be recoverable.



*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

*Potential Safety Citations*

The SED periodically audits utility operating practices, conducts investigations of potential violations, and has authority to issue citations and impose fines on the utilities for violations of applicable laws and regulations. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken.

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations identified through the Utility's self-reports, SED investigations and audits. The Utility believes it is probable that the SED will impose fines or take other enforcement action based on some of the Utility's remaining self-reports or based on allegations contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

***Federal and State Matters***

*Federal Criminal Indictment*

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also seeks an alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment.

The trial is set to begin March 8, 2016. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Condensed Consolidated Financial Statements as such amounts are not considered to be probable.



*Other Federal and State Matters*

The U.S. Attorney's Office in San Francisco and the California Attorney General's office have also begun investigations in connection with the ex parte communications (see "Improper CPUC Communications" above). The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility. In addition, the Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. (For more information refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations−Enforcement and Litigation Matters" appearing under Item 7 and in Note 14 of the Notes to the Consolidated Financial Statements appearing under Item 8 in the 2014 Annual Report on Form 10-K). It is uncertain whether any charges will be brought against the Utility. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case.

**Other Pending Lawsuits and Claims**

At March 31, 2015, there were five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

PG&E Corporation received a letter, dated March 26, 2015, on behalf of a purported shareholder demanding that the PG&E Corporation Board of Directors (1) take all necessary actions to recover from certain officers and directors the amount of damages sustained by PG&E Corporation as a result of their alleged misconduct in connection with the events surrounding the San Bruno accident and other matters, and (2) institute corporate governance changes and improvements. The Board is in the process of determining an appropriate response to the demands set forth in the letter.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

**RATEMAKING PROCEEDINGS**

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. Significant regulatory developments that have occurred since the 2014 Form 10-K was filed with the SEC are discussed below.

**2015 Gas Transmission and Storage Rate Case**

Hearings in the 2015 GT&S rate case concluded on March 23, 2015. The current procedural schedule calls for a final decision to be issued in August 2015. It is uncertain how the Penalty Decision will affect the procedural schedule. If the final decision in the GT&S rate case is not issued by the end of 2015, PG&E Corporation and the Utility's financial results for 2015 will not reflect any associated revenues.

The Utility has requested that the CPUC authorize a 2015 revenue requirement of $1.29 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $555 million over currently authorized amounts. The Utility also requested attrition increases of $61 million in 2016 and $168 million in 2017. The Utility requested that the CPUC authorize the Utility's forecast of its 2015 weighted average rate base for its gas transmission and storage business of $3.56 billion, which includes capital spending above authorized levels for the prior rate case period.

The ORA has recommended a 2015 revenue requirement of $1.044 billion, an increase of $329 million over authorized amounts. TURN has stated that it intends to make its revenue requirement recommendation in its opening brief to be filed on April 29, 2015. Nevertheless, TURN has submitted testimony recommending that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service between January 1, 1956 and June 30, 1961, as well as certain other work that TURN considers to be remedial. TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of capital expenditures during this period be subject to a reasonableness review and an independent audit. TURN states that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit.



The final GT&S rate case decision is expected to designate the safety-related gas transmission projects and programs to be funded by shareholders, as required by the Penalty Decision. (See "Enforcement and Litigation Matter" above.) The capital that is disallowed under the Penalty Decision is prohibited from being included in rate base. In addition, as discussed above under "Improper CPUC Communications," the CPUC has issued a decision to prohibit the Utility from recovering up to five months of the revenue increase that may be authorized in the final GT&S rate case decision.

The Utility also has proposed changes to the revenue sharing mechanism authorized in the last GT&S rate case (covering 2011-2014) that subjected a portion of the Utility's transportation and storage revenue requirement to market risk. The Utility proposed full balancing account treatment that allows for recovery of the Utility's authorized transportation and storage revenue requirements except for the revenue requirement associated with the Utility's 25% interest in the Gill Ranch storage field.

**FERC Transmission Owner (TO) Rate Cases**

The Utility has one TO rate case pending at the FERC. The Utility has requested a 2015 retail electric transmission revenue requirement of $1.366 billion, a $326 million increase to the currently authorized revenue requirement of $1.040 billion. The proposed rates went into effect on March 1, 2015, subject to refund, and pending a final decision by the FERC. The Utility's 2015 cost forecasts reflect the continuing need to replace and modernize aging electric transmission infrastructure, to meet the need for increased capacity in the CAISO controlled grid, and to comply with new rules aimed at ensuring the physical and cyber security of the nation's electric system. The Utility forecasts that it will make investments of $1.125 billion in 2015 in various capital projects. The Utility's proposed rate base for 2015 is $5.12 billion, compared to $4.57 billion in 2014. The Utility has requested that the FERC approve an 11.26% return on equity. The procedural schedule is currently being held in abeyance while settlement discussions are held.

## ELECTRIC DISTRIBUTION RESOURCES

California law requires the Utility and other California electrical corporations to file proposals for the development of electric distribution resources to facilitate the integration of distributed energy resources at optimal locations in the distribution system to minimize overall system costs and maximize customer benefits from new energy technologies. The proposals must be filed by July 1, 2015. The Utility's proposal will describe its vision of the electric grid of the future, titled the Grid of Things™, as a "plug-and-play" platform that would allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions an electric grid that would allow customers to choose new advanced energy supply technologies and services to meet their needs. Some of the Utility's initiatives include smart grid infrastructure modernization, new community solar programs, and a proposal for electric vehicle infrastructure development (see "Proposal for Electric Vehicle Infrastructure Development" below).

*Proposal for Electric Vehicle Infrastructure Development*

On February 9, 2015, the Utility filed an application requesting the CPUC to approve the Utility's proposal to deploy, own and maintain EV charging infrastructure in its service territory to accelerate EV infrastructure deployment and customer education programs in support of California's climate goals. Future use of this charging infrastructure could aid the integration of increased intermittent renewable energy on the state's electric power grid. Under the Utility's proposal, the Utility would develop more than 25,000 EV charging stations and the associated infrastructure over an estimated five years. The Utility estimates this would meet approximately 25% of projected EV charging station needs by 2020. The Utility plans to contract with third party EV service providers to operate and maintain the charging stations. The Utility estimates that it would incur capital costs of $551 million and operating costs of $103 million over the proposed project timeline. The Utility has requested that the CPUC authorize the Utility to collect an average annual revenue requirement over the project development years of $81 million to recover these costs. The Utility has requested that the CPUC issue a decision before the end of 2015.



*Electric Rate Reform*

New state legislation that became effective on January 1, 2014 (AB 327) grants the CPUC authority to approve fixed charges to be collected from residential customers. In 2012, the CPUC began a rulemaking proceeding to examine residential rate design in California that, consistent with AB 327, allows the CPUC to simplify the rate structure and bring rates closer to actual costs. In February 2014, as ordered by the CPUC, the Utility submitted a long-term rate reform plan that proposes a fixed customer charge, gradual flattening of the tiered rate structure, and an optional time-of-use rate. On April 21, 2015, a proposed decision was issued that, if adopted by the CPUC, would approve the gradual flattening of the tiered rate structure and an optional time-of-use rate, but would defer the approval of a fixed customer charge to a later date. The proposed decision would require the Utility to file a proposal for a default time-of-use rate no later than January 1, 2018. After receiving comments on the proposed decision, the CPUC is expected to issue a final decision in the summer of 2015.

AB 327 also requires the CPUC to develop a new tariff or contract for net energy metering by December 31, 2015, that must be implemented no later than July 1, 2017. California's net energy metering tariff currently allows customers installing renewable distributed generation to offset their electric consumption and receive bill credits for power delivered to the grid at their full retail rate. Increasing levels of installed renewable distributed generation by customers, coupled with net energy metering that provides full retail rate credits that do not reflect the Utility's cost structure, has shifted costs from distributed generation customers to other customers. AB 327 requires the CPUC to assess opportunities to reduce this cost-shift through residential rate and net energy metering tariff reform. In July 2014, the CPUC began a new rulemaking proceeding to develop a successor to the existing net energy metering tariff to comply with the requirements of AB 327. The CPUC is expected to issue a decision by December 2015.

If the CPUC fails to appropriately adjust the Utility's rate design to bring rates into alignment with the Utility's cost structure, or to adequately address the rate impact of net energy metering and the growth of renewable distributed generation, there will be increasing rate pressure on customers. This increasing rate pressure could, in turn, cause more customers to seek alternative energy providers or sources, further exacerbating the risk of a reduction in customers from whom the Utility can recover its costs.

**ENVIRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes, such as groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations; the reporting and reduction of carbon dioxide and other greenhouse gas emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements, above, and "Item 1A. Risk Factors" and Note 14 in the 2014 Form 10-K.)

**CONTRACTUAL COMMITMENTS**

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that relate to purchases of electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and purchases of fuel and transportation to support the Utility's generation activities. (See "Commitments" in Note 9 of the Notes to the Condensed Consolidated Financial Statements). Contractual commitments that relate to financing arrangements include long-term debt, preferred stock, and certain forms of regulatory financing. For more in-depth discussion about PG&E Corporation's and the Utility's contractual commitments, see "Liquidity and Financial Resources" above and Management's Discussion and Analysis of Financial Condition and Results of Operations - Contractual Commitments in the 2014 Form 10-K.

**Off-Balance Sheet Arrangements**

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 14 of the Notes to the Consolidated Financial Statements in the 2014 Form 10-K (the Utility's commodity purchase agreements).

## RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances and offset credits, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. These activities are discussed in detail in the 2014 Form 10-K. There were no significant developments to the Utility and PG&E Corporation's risk management activities during the three months ended March 31, 2015.

## CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, asset retirement obligations, and pension and other postretirement benefits plans to be critical accounting policies. These policies are considered critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates. These accounting policies and their key characteristics are discussed in detail in the 2014 Form 10-K.

## ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

### *Presentation of Debt Issuance Costs*

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*, which amends existing presentation of debt issuance costs. PG&E Corporation and the Utility currently disclose debt issuance costs in current assets - other and noncurrent assets - other. The amendments in this Accounting Standard Update, effective on January 1, 2016, require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility will adopt this standard starting in the first quarter of 2016.

### *Accounting for Fees Paid in a Cloud Computing Arrangement*

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update No. 2015-05, *Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement*, which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. The accounting standards update will be effective on January 1, 2016. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

***Revenue Recognition Standard***

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers*, which amends existing revenue recognition guidance. The accounting standards update will be effective on January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.



**CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS**

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management’s judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as “assume,” “expect,” “intend,” “forecast,” “plan,” “project,” “believe,” “estimate,” “predict,” “anticipate,” “may,” “should,” “would,” “could,” “potential” and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- The outcome and timing of the 2015 GT&S rate case, including the amount of revenue disallowance imposed as a penalty for improper ex-parte communications;

- the timing and amount of fines, penalties, and remedial costs that the Utility may incur in connection with the federal criminal prosecution of the Utility, the CPUC’s investigation of the Utility’s natural gas distribution operations, the SED’s unresolved enforcement action matters, and the other investigations that have been or may be commenced relating to the Utility’s compliance with natural gas-related laws and regulations;

- the timing and outcome of the CPUC’s investigation and the pending criminal investigations relating to communications between the Utility and the CPUC that may have violated the CPUC’s rules regarding ex parte communications or are otherwise alleged to be improper, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other ratemaking proceedings;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the criminal prosecution of the Utility, the state and federal investigations of natural gas incidents, improper communications between the CPUC and the Utility; and the Utility’s ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the restrictions on communications between the Utility and the CPUC that have been imposed by the CPUC that, along with continuing public criticism of the Utility and the CPUC, may make it more difficult for the Utility to sustain or repair a constructive working relationship with the CPUC and achieve balanced regulatory outcomes;

- the timing and outcome of ratemaking proceedings (such as the 2015 GT&S rate case, the 2017 GRC and the TO rate case) and the Utility’s ability to control its costs within the adopted levels of spending;

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, the proceeds of which are contributed as equity to maintain the Utility's authorized capital structure as the Utility incurs charges and costs that it cannot recover through rates (including $850 million of shareholder-funded costs to complete designated safety projects and programs as ordered in the Penalty Decision) and fines;

- the outcome of the anticipated CPUC investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

- the outcomes of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security; and whether the current or potentially worsening state regulatory environment increases the likelihood of unfavorable outcomes;



- the impact of environmental laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover environmental costs in rates or from other sources; and the ultimate amount of environmental costs the Utility incurs but does not recover, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; and whether the Utility decides to request that the NRC resume processing the Utility's renewal application for the two Diablo Canyon operating licenses, and if so, whether the NRC grants the renewal;

- the impact of droughts or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;

- the impact of environmental laws and regulations aimed at the reduction of greenhouse gasses, and whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility's business strategy to address the impact of growing distributed and renewable generation resources and changing customer demands is successful;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the criminal prosecution, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;



- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see "Risk Factors" in the 2014 Form 10-K and in Part II, Item. 1.A. Risk Factors below. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. (See the section above entitled "Risk Management Activities" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.)

## ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of March 31, 2015, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended March 31, 2015, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.



# PART II. OTHER INFORMATION

## ITEM 1. LEGAL PROCEEDINGS

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 9 of the Notes to the Condensed Consolidated Financial Statements.

**CPUC Investigations**

On April 9, 2015, the CPUC approved final decisions in the three investigations pending against the Utility relating to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also issued a decision to impose penalties on the Utility totaling $1.6 billion. The penalties, to be funded by shareholders, are comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. PG&E Corporation's and the Utility's financial results for the three months ended March 31, 2015, reflect the financial impact of the Penalty Decision. For additional information, see Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 9 of the Notes to the Condensed Consolidated Financial Statements.

**Federal Criminal Indictment**

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also seeks an alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility continues to believe that criminal charges are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. The trial is set to begin March 8, 2016. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their condensed consolidated financial statements as such amounts are not considered to be probable.

**Litigation Related to the San Bruno Accident and Natural Gas Spending**

At March 31, 2015, there were five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

PG&E Corporation received a letter, dated March 26, 2015, on behalf of a purported shareholder demanding that the PG&E Corporation Board of Directors (1) take all necessary actions to recover from certain officers and directors the amount of damages sustained by PG&E Corporation as a result of their alleged misconduct in connection with the events surrounding the San Bruno accident and other matters, and (2) institute corporate governance changes and improvements. The Board is in the process of determining an appropriate response to the demands set forth in the letter.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.



For additional information regarding these matters, see the discussion entitled "Enforcement and Litigation Matters" above in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2014 Form 10-K.

**Other Enforcement Matters**

In addition, fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, investigations that were commenced after a pipeline explosion in Carmel, California on March 3, 2014, and other enforcement matters. See the discussion entitled "Enforcement and Litigation Matters" above in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2014 Form 10-K.

**Diablo Canyon Nuclear Power Plant**

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board and the Utility, see "Part I, Item 3. Legal Proceedings" in the 2014 Form 10-K.



## ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see the section of the 2014 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Cautionary Language Regarding Forward-Looking Statements."

***PG&E Corporation's and the Utility's future financial results will continue to be materially affected as the Utility complies with the Penalty Decision and also may be materially affected by the outcomes of new CPUC investigative enforcement proceedings that are expected to be brought against the Utility, the ongoing federal criminal prosecution of the Utility, and the other federal, state and regulatory investigations and enforcement matters discussed above.***

PG&E Corporation's EPS will be materially affected by dilutive common stock issuances needed to fund equity contributions to the Utility to comply with the terms of the Penalty Decision, as discussed above. The Utility will incur material unrecoverable costs to meet the Penalty Decision's requirement to fund safety-related projects and programs to be identified in the final GT&S rate case decision. Although the final GT&S rate case decision is scheduled to be issued in August 2015, the decision may be delayed as needed to comply with the requirements of the Penalty Decision. If the final decision in the GT&S rate case is not issued by the end of 2015, PG&E Corporation and the Utility's financial results for 2015 will not reflect any associated revenue increases. (The final GT&S rate case decision may also disallow up to five months of the authorized revenue increase per the CPUC's November 2014 decision to penalize the Utility for violations of the ex parte communications rules.) The ultimate financial impact of the Penalty Decision will be affected by the tax treatment of the costs the Utility incurs to comply with the Penalty Decision. In statements made at the CPUC meeting at which the Penalty Decision was approved, the participating Commissioners indicated that they would inform state and federal tax authorities that the CPUC intended the shareholder-funded costs to be characterized as penalties and not a "cost of doing business."

In addition, the CPUC stated in the Penalty Decision that it would begin an investigation into the City of San Bruno's allegations that the Utility violated the CPUC's rules regarding ex parte communications. As discussed in the 2014 Form 10-K, the CPUC also may bring enforcement action against the Utility relating to other communications between the Utility and the CPUC. PG&E Corporation's and the Utility's financial results could be materially affected by fines or penalties that may be imposed by the CPUC. Federal and state law enforcement authorities also have begun investigations in connection with these matters and they could take enforcement action in the future against the Utility.

In addition, the Utility could incur material charges, including fines and other penalties, in connection with the CPUC's investigation of the Utility's compliance with natural gas distribution record-keeping practices, the SED's review of the Utility's natural gas distribution practices and procedures, and the self-reports the Utility has submitted to the CPUC in accordance with the SED's safety citation program. Further, if the Utility is convicted of federal criminal charges that the Utility knowingly and willfully violated pipeline safety laws and illegally obstructed the NTSB's investigation into the cause of the San Bruno accident, the Utility could be required to pay a material amount of fines. Based on the superseding indictment's allegations, the maximum alternative fine would be approximately $1.13 billion. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case. The Utility also could incur a material amount of costs to comply with remedial measures that the CPUC or a federal judge may impose on the Utility, such as a requirement that the Utility's natural gas operations be supervised by a third-party monitor.

Further, the CPUC is expected to begin a new investigation to examine the Utility's safety culture and practices, including whether they are effective and comprehensive across the organization, and whether there is sufficient accountability for safety results. The President of the CPUC also has questioned whether the Utility "is too big to succeed" from a safety perspective and has requested the CPUC's Legal Division to analyze and evaluate the CPUC's policies regarding penalties and remedies, and make recommendations for adoption by the CPUC. The scope, timing, and outcome of the new investigation are uncertain.



## ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the quarter ended March 31, 2015, PG&E Corporation made equity contributions totaling $100 million to the Utility in order to maintain the 52% common equity component of its CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended March 31, 2015.

**Issuer Purchases of Equity Securities**

During the quarter ended March 31, 2015, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended March 31, 2015, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

## ITEM 5. OTHER INFORMATION

**Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends**

The Utility's earnings to fixed charges ratio for the three months ended March 31, 2015 was 0.65. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2015 was 0.64. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement No. 333-193879.

PG&E Corporation's earnings to fixed charges ratio for the three months ended March 31, 2015 was 0.75. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-193880.

**Senior Unsecured Credit Facility**

The information below is reported in lieu of information that would be reported under Items 1.01 and 2.03 under
Form 8-K:

*PG&E Corporation*

On April 27, 2015, PG&E Corporation entered into an amendment and restatement of its $300 million senior unsecured five-year revolving credit agreement that it entered into on April 1, 2013. The amended and restated credit agreement is with (1) Bank of America, N.A., as administrative agent and a lender, (2) Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (3) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (4) Wells Fargo Bank, National Association, as documentation agent and a lender, and (5) certain other lenders.

The amended and restated credit agreement includes a $100 million sublimit for the issuance of standby and commercial letters of credit (for which $50 million of commitments to issue letters of credit have been provided by the lenders) and a $100 million commitment for swingline loans. The credit facility will be used for working capital and other corporate purposes, including commercial paper back-up.

Subject to obtaining commitments from existing or new lenders and satisfaction of other specified conditions, PG&E Corporation has the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the amended and restated credit agreement by up to $100 million in the aggregate for all such increases.

The amended and restated credit agreement has a term of five years from its effective date, and all amounts borrowed under the agreement are due and payable on April 27, 2020. At PG&E Corporation's request, given not more frequently than once a year and on not more than two occasions over the term of the facility, and at the sole discretion of each lender, the facility may be extended for an additional period not exceeding one year in each instance. PG&E Corporation has the right to replace any lender who does not agree to an extension.



Borrowings under the amended and restated credit agreement (other than swingline loans) will bear interest based, at PG&E Corporation's election, on (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The applicable margin for LIBOR loans under the amended and restated credit agreement will range between 0.9% and 1.475% and the applicable margin for base rate loans under the amended and restated credit agreement will range between 0% and 0.475%. PG&E Corporation will also pay a facility fee based on total lender commitments which will range between 0.1% and 0.275%. The specific facility fee and applicable margin will be based on the senior unsecured, non-credit enhanced debt ratings of PG&E Corporation issued by Standard & Poor's Ratings Services and Moody's Investors Service, Inc.

The amended and restated credit agreement includes usual and customary covenants for credit facilities of this type, including covenants limiting (1) liens, except for specified permitted liens, (2) mergers, (3) sales of all or substantially all of PG&E Corporation's assets and (4) other fundamental changes. In addition, the amended and restated credit agreement requires that PG&E Corporation maintain a ratio of total consolidated debt to total consolidated capitalization of not more than 0.65 to 1.00 as of the end of each fiscal quarter.

In the event of a default by PG&E Corporation under the amended and restated credit agreement, including cross-defaults relating to specified other debt of PG&E Corporation or any of its significant subsidiaries in excess of $200 million, the lenders may terminate the commitments under the amended and restated credit agreement and declare the amounts outstanding, including all accrued interest and unpaid fees, payable immediately. For events of default relating to insolvency, bankruptcy or receivership, the commitments are automatically terminated and the amounts outstanding become payable immediately.

*Utility*

On April 27, 2015, the Utility entered into an amendment and restatement of its $3.0 billion senior unsecured five-year revolving credit agreement that it entered into on April 1, 2013. The amended and restated credit agreement is with (1) Citibank, N.A., as administrative agent and a lender, (2) Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (3) Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (4) Wells Fargo Bank, National Association, as documentation agent and a lender, and (5) certain other lenders.

The credit facility will be used for working capital and other corporate purposes, including commercial paper back-up. The amended and restated credit agreement includes a $1.0 billion sublimit (for which $500 million of commitments to issue letters of credit have been provided by the lenders) for the issuance of standby and commercial letters of credit and a $75 million commitment for swingline loans; i.e., loans made available on a same day basis and repayable in full within seven days.

Subject to obtaining commitments from existing or new lenders and satisfaction of other specified conditions, the Utility has the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the amended and restated credit agreement by up to $500 million in the aggregate for all such increases.

The amended and restated credit agreement has a term of five years from its effective date, and all amounts borrowed under the agreement are due and payable on April 27, 2020. At the Utility's request, given not more frequently than once a year and on not more than two occasions over the term of the facility, and at the sole discretion of each lender, the facility may be extended for an additional period not exceeding one year in each instance. The Utility has the right to replace any lender who does not agree to an extension.

Borrowings under the amended and restated credit agreement (other than swingline loans) will bear interest based, at the Utility's election, on (1) LIBOR plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The applicable margin for LIBOR loans under the amended and restated credit agreement will range between 0.8% and 1.275% and the applicable margin for base rate loans under the amended and restated credit agreement will range between 0% and 0.275%. The Utility will also pay a facility fee based on total lender commitments which will range between 0.075% and 0.225%. The specific facility fee and applicable margin will be based on the senior unsecured, non-credit enhanced debt ratings of the Utility issued by Standard & Poor's Ratings Services and Moody's Investors Service, Inc.



The amended and restated credit agreement includes usual and customary covenants for credit facilities of this type, including covenants limiting: (1) liens to those permitted under the Utility's senior bond indenture, (2) mergers, (3) sales of all or substantially all of the Utility's assets and (4) other fundamental changes. In addition, the amended and restated credit agreement requires that the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of not more than 0.65 to 1.00 as of the end of each fiscal quarter.

In the event of a default by the Utility under the amended and restated credit agreement, including cross-defaults relating to specified other debt of the Utility or any of its significant subsidiaries in excess of $200 million, the lenders may terminate the commitments under the amended and restated credit agreement and declare the amounts outstanding, including all accrued interest and unpaid fees, payable immediately. For events of default relating to insolvency, bankruptcy or receivership, the commitments are automatically terminated and the amounts outstanding become payable immediately.

**General**

The lenders and agents under PG&E Corporation's and the Utility's amended and restated credit agreements and their affiliates have in the past provided, and may in the future provide, investment banking, underwriting, lending, commercial banking and other advisory services to PG&E Corporation and the Utility. These parties have received, and may in the future receive, customary compensation from PG&E Corporation and the Utility for such services.



## ITEM 6. EXHIBITS

| | |
|---|---|
| 10.1 | Amended and restated credit agreement dated April 27, 2015, among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation |
| 10.2 | Amended and restated credit agreement dated April 27, 2015, among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation |
| *10.3 | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2015 |
| *10.4 | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.5 | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.6 | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |

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| *10.7 | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.8 | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.9 | Performance Share Agreement subject to safety and customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 12.1 | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 31.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| **32.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| **32.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |



| | |
|---|---|
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

*Management contract or compensatory agreement.
**Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.



**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

KENT M. HARVEY

Kent M. Harvey
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

DINYAR B. MISTRY

Dinyar B. Mistry
Vice President, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: April 29, 2015



**EXHIBIT INDEX**

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10.2 Amended and restated credit agreement dated April 27, 2015, among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation

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| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

# Exhibit 8

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C., 20549**
**FORM 10-Q**

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2016

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to __________

| Commission File Number | Exact Name of Registrant as Specified in its Charter | State or Other Jurisdiction of Incorporation | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E Corporation | California | 94-3234914 |
| 1-2348 | Pacific Gas and Electric Company | California | 94-0742640 |

| | |
|---|---|
| PG&E Corporation<br>77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177 | Pacific Gas and Electric Company<br>77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177 |

Address of principal executive offices, including zip code

| | |
|---|---|
| PG&E Corporation<br>(415) 973 - 1000 | Pacific Gas and Electric Company<br>(415) 973-7000 |

Registrant's telephone number, including area code

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. [X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation : | [X] Yes [ ] No |
| Pacific Gas and Electric Company: | [X] Yes [ ] No |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | | |
|---|---|---|
| PG&E Corporation: | [X] Large accelerated filer | [ ] Accelerated filer |
| | [ ] Non-accelerated filer | [ ] Smaller reporting company |
| Pacific Gas and Electric Company: | [ ] Large accelerated filer | [ ] Accelerated filer |
| | [X] Non-accelerated filer | [ ] Smaller reporting company |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation: | [ ] Yes [X] No |
| Pacific Gas and Electric Company: | [ ] Yes [X] No |

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding as of April 19, 2016 :

| | |
|---|---|
| PG&E Corporation : | 496,042,305 |
| Pacific Gas and Electric Company : | 264,374,809 |

**PG&E CORPORATION AND**
**PACIFIC GAS AND ELECTRIC COMPANY**
**FORM 10-Q**
**FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2016**

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  - CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
  - CONDENSED CONSOLIDATED BALANCE SHEETS
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## GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2015 Form 10-K | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2015 |
| AFUDC | allowance for funds used during construction |
| ALJ | Administrative Law Judge |
| ARO(s) | asset retirement obligation(s) |
| ASU | Accounting Standards Update issued by the FASB (see below) |
| Cal Fire | California Department of Forestry and Fire Protection |
| CAISO | California Independent System Operator Corporation |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DOI | U.S. Department of the Interior |
| DTSC | California Department of Toxic Substances Control |
| EMANI | European Mutual Association for Nuclear Insurance |
| EPS | earnings per common share |
| EV | electric vehicle |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| IOU(s) | investor-owned utility(ies) |
| IRS | Internal Revenue Service |
| NAV | net asset value |
| NDCTP | Nuclear Decommissioning Cost Triennial Proceedings |
| NEIL | Nuclear Electric Insurance Limited |
| NEM | Net Energy Metering |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| OII | order instituting investigation |
| ORA | Office of Ratepayer Advocates |
| PSEP | pipeline safety enhancement plan |
| Regional Board | California Regional Water Control Board, Lahontan Region |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

| | (Unaudited) Three Months Ended March 31, | |
|---|---|---|
| **(in millions, except per share amounts)** | **2016** | **2015** |
| **Operating Revenues** | | |
| Electric | $ 3,131 | $ 3,013 |
| Natural gas | 843 | 886 |
| **Total operating revenues** | **3,974** | **3,899** |
| **Operating Expenses** | | |
| Cost of electricity | 950 | 1,000 |
| Cost of natural gas | 222 | 274 |
| Operating and maintenance | 2,010 | 1,923 |
| Depreciation, amortization, and decommissioning | 697 | 631 |
| **Total operating expenses** | **3,879** | **3,828** |
| **Operating Income** | **95** | **71** |
| Interest income | 4 | 1 |
| Interest expense | (203) | (189) |
| Other income, net | 27 | 58 |
| **Loss Before Income Taxes** | **(77)** | **(59)** |
| Income tax benefit | (187) | (93) |
| **Net Income** | **110** | **34** |
| **Preferred stock dividend requirement of subsidiary** | 3 | 3 |
| **Income Available for Common Shareholders** | **$ 107** | **$ 31** |
| **Weighted Average Common Shares Outstanding, Basic** | **493** | **477** |
| **Weighted Average Common Shares Outstanding, Diluted** | **495** | **481** |
| **Net Earnings Per Common Share, Basic** | **$ 0.22** | **$ 0.06** |
| **Net Earnings Per Common Share, Diluted** | **$ 0.22** | **$ 0.06** |
| **Dividends Declared Per Common Share** | **$ 0.46** | **$ 0.46** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | (Unaudited) | |
|---|---|---|
| | Three Months Ended March 31, | |
| **(in millions)** | **2016** | **2015** |
| Net Income | $ 110 | 34 |
| **Other Comprehensive Income** | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0 and $0, at respective dates) | - | - |
| Net change in investments (net of taxes of $0 and $12, at respective dates) | - | (17) |
| **Total other comprehensive income (loss)** | **-** | **(17)** |
| **Comprehensive Income** | **110** | **17** |
| **Preferred stock dividend requirement of subsidiary** | **3** | **3** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 107** | **14** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions) | March 31, 2016 | December 31, 2015 |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 142 | $ 123 |
| Restricted cash | 234 | 234 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $55 and $54 at respective dates) | 1,010 | 1,106 |
| Accrued unbilled revenue | 685 | 855 |
| Regulatory balancing accounts | 1,721 | 1,760 |
| Other | 328 | 286 |
| Regulatory assets | 504 | 517 |
| Inventories: | | |
| Gas stored underground and fuel oil | 109 | 126 |
| Materials and supplies | 344 | 313 |
| Income taxes receivable | 230 | 155 |
| Other | 327 | 338 |
| **Total current assets** | **5,634** | **5,813** |
| **Property, Plant, and Equipment** | | |
| Electric | 49,974 | 48,532 |
| Gas | 16,982 | 16,749 |
| Construction work in progress | 2,148 | 2,059 |
| Other | 2 | 2 |
| **Total property, plant, and equipment** | **69,106** | **67,342** |
| Accumulated depreciation | (21,062) | (20,619) |
| **Net property, plant, and equipment** | **48,044** | **46,723** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,130 | 7,029 |
| Nuclear decommissioning trusts | 2,516 | 2,470 |
| Income taxes receivable | 153 | 135 |
| Other | 1,173 | 1,064 |
| **Total other noncurrent assets** | **10,972** | **10,698** |
| **TOTAL ASSETS** | **$ 64,650** | **$ 63,234** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions, except share amounts) | March 31, 2016 | December 31, 2015 |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 693 | $ 1,019 |
| Long-term debt, classified as current | 160 | 160 |
| Accounts payable: | | |
| Trade creditors | 1,062 | 1,414 |
| Regulatory balancing accounts | 704 | 715 |
| Other | 598 | 398 |
| Disputed claims and customer refunds | 457 | 454 |
| Interest payable | 145 | 206 |
| Other | 2,155 | 1,997 |
| **Total current liabilities** | **5,974** | **6,363** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 16,522 | 15,925 |
| Regulatory liabilities | 6,486 | 6,321 |
| Pension and other postretirement benefits | 2,629 | 2,622 |
| Asset retirement obligations | 4,480 | 3,643 |
| Deferred income taxes | 9,323 | 9,206 |
| Other | 2,372 | 2,326 |
| **Total noncurrent liabilities** | **41,812** | **40,043** |
| **Commitments and Contingencies (Note 9)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 495,606,702 and 492,025,443 shares outstanding at respective dates | 11,440 | 11,282 |
| Reinvested earnings | 5,179 | 5,301 |
| Accumulated other comprehensive loss | (7) | (7) |
| **Total shareholders' equity** | **16,612** | **16,576** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **16,864** | **16,828** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 64,650** | **$ 63,234** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | (Unaudited) | |
|---|---|---|
| | Three Months Ended March 31, | |
| **(in millions)** | **2016** | **2015** |
| **Cash Flows from Operating Activities** | | |
| Net income | $ 110 | $ 34 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 697 | 631 |
| Allowance for equity funds used during construction | (27) | (28) |
| Deferred income taxes and tax credits, net | 117 | 113 |
| Disallowed capital expenditures | 87 | 53 |
| Other | 73 | 52 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | 210 | 236 |
| Inventories | (14) | 58 |
| Accounts payable | (65) | (46) |
| Income taxes receivable/payable | (75) | 3 |
| Other current assets and liabilities | 146 | (114) |
| Regulatory assets, liabilities, and balancing accounts, net | (87) | 195 |
| Other noncurrent assets and liabilities | (117) | (107) |
| **Net cash provided by operating activities** | **1,055** | **1,080** |
| **Cash Flows from Investing Activities** | | |
| Capital expenditures | (1,229) | (1,191) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 439 | 417 |
| Purchases of nuclear decommissioning trust investments | (463) | (505) |
| Other | 3 | 7 |
| **Net cash used in investing activities** | **(1,250)** | **(1,272)** |
| **Cash Flows from Financing Activities** | | |
| Net issuances (repayments) of commercial paper, net of discount of $1 in 2016 | (577) | 223 |
| Short-term debt financing | 250 | - |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 in 2016 | 594 | - |
| Common stock issued | 146 | 151 |
| Common stock dividends paid | (219) | (211) |
| Other | 20 | 23 |
| **Net cash provided by financing activities** | **214** | **186** |
| **Net change in cash and cash equivalents** | **19** | **(6)** |
| **Cash and cash equivalents at January 1** | **123** | **151** |
| **Cash and cash equivalents at March 31** | **$ 142** | **$ 145** |

| | | | | |
|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | |
| Cash received (paid) for: | | | | |
| Interest, net of amounts capitalized | $ | (242) | $ | (216) |
| **Supplemental disclosures of noncash investing and financing activities** | | | | |
| Common stock dividends declared but not yet paid | $ | 226 | $ | 218 |
| Capital expenditures financed through accounts payable | | 373 | | 217 |
| Noncash common stock issuances | | 6 | | 5 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**P ACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

| | (Unaudited) Three Months Ended March 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| **Operating Revenues** | | |
| Electric | $ 3,132 | $ 3,014 |
| Natural gas | 843 | 886 |
| **Total operating revenues** | **3,975** | **3,900** |
| **Operating Expenses** | | |
| Cost of electricity | 950 | 1,000 |
| Cost of natural gas | 222 | 274 |
| Operating and maintenance | 2,011 | 1,923 |
| Depreciation, amortization, and decommissioning | 696 | 631 |
| **Total operating expenses** | **3,879** | **3,828** |
| **Operating Income** | 96 | 72 |
| Interest income | 4 | 1 |
| Interest expense | (201) | (187) |
| Other income, net | 24 | 26 |
| **Loss Before Income Taxes** | **(77)** | **(88)** |
| Income tax benefit | (185) | (92) |
| **Net Income** | **108** | **4** |
| Preferred stock dividend requirement | 3 | 3 |
| **Income Available for Common Stock** | **$ 105** | **$ 1** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | (Unaudited) | | |
|---|---|---|---|
| | Three Months Ended March 31, | | |
| (in millions) | 2016 | | 2015 |
| **Net Income** | $ | 108 | 4 |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0 and $0, at respective dates ) | | - | - |
| **Total other comprehensive income (loss)** | | - | - |
| **Comprehensive Income** | $ | 108 | 4 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions) | March 31, 2016 | December 31, 2015 |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 44 | $ 59 |
| Restricted cash | 234 | 234 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $55 and $54 at respective dates) | 1,010 | 1,106 |
| Accrued unbilled revenue | 685 | 855 |
| Regulatory balancing accounts | 1,721 | 1,760 |
| Other | 353 | 284 |
| Regulatory assets | 504 | 517 |
| Inventories: | | |
| Gas stored underground and fuel oil | 109 | 126 |
| Materials and supplies | 344 | 313 |
| Income taxes receivable | 204 | 130 |
| Other | 327 | 338 |
| **Total current assets** | **5,535** | **5,722** |
| **Property, Plant, and Equipment** | | |
| Electric | 49,974 | 48,532 |
| Gas | 16,982 | 16,749 |
| Construction work in progress | 2,148 | 2,059 |
| **Total property, plant, and equipment** | **69,104** | **67,340** |
| Accumulated depreciation | (21,060) | (20,617) |
| **Net property, plant, and equipment** | **48,044** | **46,723** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,130 | 7,029 |
| Nuclear decommissioning trusts | 2,516 | 2,470 |
| Income taxes receivable | 153 | 135 |
| Other | 1,061 | 958 |
| **Total other noncurrent assets** | **10,860** | **10,592** |
| **TOTAL ASSETS** | **$ 64,439** | **$ 63,037** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions, except share amounts) | March 31, 2016 | December 31, 2015 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 693 | $ 1,019 |
| Long-term debt, classified as current | 160 | 160 |
| Accounts payable: | | |
| Trade creditors | 1,062 | 1,414 |
| Regulatory balancing accounts | 704 | 715 |
| Other | 646 | 418 |
| Disputed claims and customer refunds | 457 | 454 |
| Interest payable | 144 | 203 |
| Other | 1,906 | 1,750 |
| **Total current liabilities** | **5,772** | **6,133** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 16,174 | 15,577 |
| Regulatory liabilities | 6,486 | 6,321 |
| Pension and other postretirement benefits | 2,540 | 2,534 |
| Asset retirement obligations | 4,480 | 3,643 |
| Deferred income taxes | 9,605 | 9,487 |
| Other | 2,331 | 2,282 |
| **Total noncurrent liabilities** | **41,616** | **39,844** |
| **Commitments and Contingencies (Note 9)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 7,280 | 7,215 |
| Reinvested earnings | 8,188 | 8,262 |
| Accumulated other comprehensive income | 3 | 3 |
| **Total shareholders' equity** | **17,051** | **17,060** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 64,439** | **$ 63,037** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

P ACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | (Unaudited) | |
|---|---|---|
| | Three Months Ended March 31, | |
| (in millions) | 2016 | 2015 |
| **Cash Flows from Operating Activities** | | |
| Net income | $ 108 | $ 4 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 696 | 631 |
| Allowance for equity funds used during construction | (27) | (28) |
| Deferred income taxes and tax credits, net | 118 | 112 |
| Disallowed capital expenditures | 87 | 53 |
| Other | 68 | 45 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | 183 | 215 |
| Inventories | (14) | 58 |
| Accounts payable | (37) | 26 |
| Income taxes receivable/payable | (74) | 2 |
| Other current assets and liabilities | 151 | (123) |
| Regulatory assets, liabilities, and balancing accounts, net | (87) | 195 |
| Other noncurrent assets and liabilities | (109) | (89) |
| **Net cash provided by operating activities** | **1,063** | **1,101** |
| **Cash Flows from Investing Activities** | | |
| Capital expenditures | (1,229) | (1,191) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 439 | 417 |
| Purchases of nuclear decommissioning trust investments | (463) | (505) |
| Other | 3 | 7 |
| **Net cash used in investing activities** | **(1,250)** | **(1,272)** |
| **Cash Flows from Financing Activities** | | |
| Net issuances (repayments) of commercial paper, net of discount of $1 in 2016 | (577) | 223 |
| Short-term debt financing | 250 | - |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 in 2016 | 594 | - |
| Preferred stock dividends paid | (3) | (3) |
| Common stock dividends paid | (179) | (179) |
| Equity contribution from PG&E Corporation | 65 | 100 |
| Other | 22 | 25 |
| **Net cash provided by financing activities** | **172** | **166** |
| **Net change in cash and cash equivalents** | (15) | (5) |
| **Cash and cash equivalents at January 1** | 59 | 55 |
| **Cash and cash equivalents at March 31** | **$ 44** | **$ 50** |

| | | | | |
|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | |
| Cash received (paid) for: | | | | |
| Interest, net of amounts capitalized | $ | (237) | $ | (211) |
| **Supplemental disclosures of noncash investing and financing activities** | | | | |
| Capital expenditures financed through accounts payable | $ | 373 | $ | 217 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

**NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION**

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility operate in one segment, as the companies assess financial performance and allocate resources on a consolidated basis .

The accompanying Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of PG&E Corporation and the Utility's financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 201 5 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 201 5 Form 10-K. This quarterly report should be read in conjunction with the 201 5 Form 10-K.

The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

**NOTE 2: SIGNIFICANT ACCOUNTING POLICIES**

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Note 2 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at March 31, 2016 , it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at March 31, 2016 , it did not consolidate any of them.

**Asset Retirement Obligations**

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the Nuclear Decommission ing Cost Triennial Proceedings . On March 1, 2016, the Utility submitted its updated decommission ing cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $ 1.4 billion , for a total estimated cost of $ 4.8 billion, due to increased estimated costs related to spent fuel storage, staffing, and out-of- state waste disposal. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. T he Utility requested that the CPUC authorize t he collection of increas ed annual revenue requirements beginning on January 1 , 2017 based on these updated cost estimates.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $ 3.3 b illion at March 31, 2016, which includes an $ 818 million adjustment to reflect the increased cost estimates described above, and $ 2.5 billion at December 31, 2015. These estimates are based on the 2016 decommissioning cost studies, prepared in accordance with the CPUC requirements. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

**Pension and Other Postretirement Benefits**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan and cash balance plan. Both plans are included in "Pension Benefits" below. Post-retirement medical and life insurance plans are included in "Other Benefits" below.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three months ended March 31, 2016 and 2015 were as follows:

| | **Pension Benefits** | | **Other Benefits** | |
|---|---|---|---|---|
| | **Three Months Ended March 31,** | | | |
| **(in millions)** | **2016** | **2015** | **2016** | **2015** |
| Service cost for benefits earned | $ 113 | $ 119 | $ 13 | $ 13 |
| Interest cost | 179 | 168 | 19 | 18 |
| Expected return on plan assets | (207) | (218) | (27) | (28) |
| Amortization of prior service cost | 2 | 4 | 4 | 5 |
| Amortization of net actuarial loss | 6 | 3 | 1 | 1 |
| **Net periodic benefit cost** | **93** | **76** | **10** | **9** |
| Regulatory account transfer [1] | (8) | 9 | - | - |
| **Total** | **$ 85** | **$ 85** | **$ 10** | **$ 9** |

[1] The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) are summarized below:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| | Three Months Ended March 31, 2016 | | |
| Beginning balance | $ (23) | $ 16 | $ (7) |
| **Amounts reclassified from other comprehensive income:** [1] | | | |
| Amortization of prior service cost (net of taxes of $1 and $2, respectively) | 1 | 2 | 3 |
| Amortization of net actuarial loss (net of taxes of $2 and $0, respectively) | 4 | 1 | 5 |
| Regulatory account transfer (net of taxes of $3 and $2, respectively) | (5) | (3) | (8) |
| **Net current period other comprehensive loss** | **-** | **-** | **-** |
| **Ending balance** | **$ (23)** | **$ 16** | **$ (7)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| | Three Months Ended March 31, 2015 | | | |
| Beginning balance | $ (21) | 15 | 17 | 11 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $2, $2, and $0, respectively) [1] | 2 | 3 | - | 5 |
| Amortization of net actuarial loss (net of taxes of $1, $0, and $0, respectively) [1] | 2 | - | - | 2 |
| Regulatory account transfer (net of taxes of $3, $2, and $0, respectively) [1] | (4) | (3) | - | (7) |
| Change in investments (net of taxes of $0, $0, and $12, respectively) | - | - | (17) | (17) |
| **Net current period other comprehensive loss** | **-** | **-** | **(17)** | **(17)** |
| **Ending balance** | $ **(21)** | **$ 15** | **$ -** | **$ (6)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above, with the exception of other investments which are held by PG&E Corporation.

**Recently Adopted Accounting Guidance**

***Fair Value Measurement***

In May 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* , which standardizes reporting practices related to the fair value hierarchy for all investments for which fair value is measured using the net asset value per share. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016 and applied the requirements retrospectively for all periods presented . The adoption of this standard did not impact their Condensed Consolidated Financial Statements. All prior periods presented in these Condensed Consolidated financial statements reflect the retrospective adoption of this guidance (See Note 8 below.)

***Accounting for Fees Paid in a Cloud Computing Arrangement***

In April 2015, the F ASB issued ASU No. 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement* , which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this guidance did not have a material impact on their Condensed Consolidated F inancial S tatements.

***Presentation of Debt Issuance Costs***

In April 2015, the F ASB issued ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,* which amends the existing guidance relating to the presentation of debt issuance costs. The amendments in this A SU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this guidance did not have a material impact on their Condensed Consolidated Financial S tatements. PG&E Corporation and the Utility reclassified $105 million and $103 million, respectively, of debt issuance costs as of December 31, 2015 with no impact to net income or total shareholders' equity previously reported. All prior periods presented in these Condensed Consolidated financial statements reflect the retrospective adoption of this guidance.

**Accounting Standards Issued But Not Yet Adopted**

***Share-based Payment Accounting***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation – Stock Compensation (Topic 718),* which amends the existing guidance relating to the accounting for share-based payment awards issued to employees, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

***Recognition of Lease Assets and Liabilities***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842),* which amends the existing guidance relating to the recognition of lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019 with retrospective application. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

***Recognition and Measurement of Financial Assets and Financial Liabilities***

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* , which amends the existing guidance relating to the recognition and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

***Revenue Recognition Standard***

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which amends the existing revenue recognition guidance . In August 2015, the FASB deferred the effective date of this amendment for public companies by one year to January 1, 2018 , with early adoption permitted as of the original effective date of January 1, 2017. (See ASU No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* .) PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

**NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS**

**Regulatory Assets**

Long-term regulatory assets are composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **December 31, 2015** |
| Pension benefits | $ 2,414 | $ 2,414 |
| Deferred income taxes | 3,265 | 3,054 |
| Utility retained generation | 399 | 411 |
| Environmental Compliance Costs | 683 | 748 |
| Price risk management | 134 | 138 |
| Unamortized loss, net of gain, on reacquired debt | 90 | 94 |
| Other | 145 | 170 |
| **Total long-term regulatory assets** | **$ 7,130** | **$ 7,029** |

For more information, see Note 3 of the Notes to the Consolidated Financ ial Statements in Item 8 of the 201 5 Form 10-K .

**Regulatory Liabilities**

Long-term regulatory liabilities are composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **December 31, 2015** |
| Cost of removal obligations | $ 4,717 | $ 4,605 |
| Recoveries in excess of asset retirement obligations | 645 | 631 |
| Public purpose programs | 620 | 600 |
| Other | 504 | 485 |
| **Total long-term regulatory liabilities** | **$ 6,486** | **$ 6,321** |

For more information, see Note 3 of the Notes to the Consolidated Financ ial Statements in Item 8 of the 201 5 Form 10-K .

**Regulatory Balancing Accounts**

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Condensed Consolidated Balance Sheets. These differences do not have an impact on net income . Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and cu stomer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

| | Receivable Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **December 31, 2015** |
| Electric distribution | $ 515 | $ 380 |
| Utility generation | 225 | 122 |
| Gas distribution | 280 | 493 |
| Energy procurement | 87 | 262 |
| Public purpose programs | 149 | 155 |
| Other | 465 | 348 |
| **Total regulatory balancing accounts receivable** | **$ 1,721** | **$ 1,760** |

| | Payable Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **December 31, 2015** |
| Energy procurement | $ 184 | $ 112 |
| Public purpose programs | 212 | 244 |
| Other | 308 | 359 |
| **Total regulatory balancing accounts payable** | **$ 704** | **$ 715** |

The electric distribution, utility generation, and gas distribution balancing accounts track the collection of revenue requirements approved in the GRC. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. P ublic purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency and low income energy efficiency.

**NOTE 4: DEBT**

**Revolving Credit Facilities and Commercial Paper Program**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at March 31, 2016 :

| **(in millions)** | **Termination Date** | **Facility Limit** | **Letters of Credit Outstanding** | **Commercial Paper** | **Facility Availability** |
|---|---|---|---|---|---|
| PG&E Corporation | April 2020 | $ 300 (1) | $ - | $ - | $ 300 |
| Utility | April 2020 | 3,000 (2) | 33 | 443 | 2,524 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 33** | **$ 443** | **$ 2,824** |

(1) Includes a $50 million lender commitment to the letter of credit sublimits and a $100 million commitment for "swingline" loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $500 million lender commitment to the letter of credit sublimits and a $75 million commitment for swingline loans.

**Other Short-term Borrowings**

I n March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

**Senior Notes Issuances**

In March 2016 , the Utility issued $ 6 00 million principal amount of 2.95 % Senior Notes due March 1, 2026. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

**Variable Rate Interest**

At March 31, 2016 , the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.37% to 0.45% . At March 31, 2016 , the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.34% to 0.38%. Pollution control bonds Series 2009 C and D will mature on December 1, 2016.

**NOTE 5: EQUITY**

PG&E Corporation's and the Utility's changes in equity for the three months ended March 31, 2016 were as follows:

| | PG&E Corporation | Utility |
|---|---|---|
| **(in millions)** | **Total Equity** | **Total Shareholders' Equity** |
| **Balance at December 31, 2015** | **$ 16,828** | **$ 17,060** |
| Comprehensive income | 110 | 108 |
| Equity contributions | - | 65 |
| Common stock issued | 152 | - |
| Share-based compensation | 6 | - |
| Common stock dividends declared | (229) | (179) |
| Preferred stock dividend requirement | - | (3) |
| Preferred stock dividend requirement of subsidiary | (3) | - |
| **Balance at March 31, 2016** | **$ 16,864** | **$ 17,051** |

During the three months ended March 31, 2016 , PG&E Corporation sold 1.3 million shares under the February 2015 equity distribution agreement for cash proceeds of $ 74 millio n, net of commissions paid of $ 1 million. As of March 31, 2016, the remaining gross sales available under this agreement were $ 350 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the three months ended March 31, 2016 , 2.3 million shares were issued for cash proceeds of $ 72 million under these plans.

**NOTE 6: EARNINGS PER SHARE**

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS:

| | Three Months Ended March 31, | |
|---|---|---|
| **(in millions, except per share amounts)** | **2016** | **2015** |
| **Income available for common shareholders** | **$ 107** | **$ 31** |
| **Weighted average common shares outstanding, basic** | 493 | 477 |
| Add incremental shares from assumed conversions: | | |
| Employee share-based compensation | 2 | 4 |
| **Weighted average common shares outstanding, diluted** | **495** | **481** |
| **Total earnings per common share, diluted** | **$ 0.22** | **$ 0.06** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

**NOTE 7: DERIVATIVES**

**Use of Derivative Instruments**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Derivatives are recorded at fair value and are pres ented in the Utility's Condensed Consolidated Balance Sheets on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives as long as the current ratemaking mechanism remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Condensed Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

**Volume of Derivative Activity**

The volumes of the Utility's outstanding derivatives were as follows:

| | | Contract Volume at | |
|---|---|---|---|
| Underlying Product | Instruments | March 31, 2016 | December 31, 2015 |
| Natural Gas [1] (MMBtus [2]) | Forwards and Swaps | 341,884,852 | 333,091,813 |
| | Options | 92,426,200 | 111,550,004 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 3,580,205 | 3,663,512 |
| | Congestion Revenue Rights [3] | 198,499,963 | 216,383,389 |

(1) Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
(2) Million British Thermal Units.
(3) CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

**Presentation of Derivative Instruments in the Financial Statements**

At March 31, 2016 , the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| (in millions) | Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
| Current assets – other | $ 91 | $ (5) | $ 12 | $ 98 |
| Other noncurrent assets – other | 173 | (5) | - | 168 |
| Current liabilities – other | (105) | 5 | 46 | (54) |
| Noncurrent liabilities – other | (139) | 5 | 16 | (118) |
| **Net commodity risk** | **$ 20** | **$ -** | **$ 74** | **$ 94** |

At December 31, 2015 , the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| (in millions) | Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
| Current assets – other | $ 97 | (4) | 25 | $ 118 |
| Other noncurrent assets – other | 172 | (2) | - | 170 |
| Current liabilities – other | (102) | 4 | 44 | (54) |
| Noncurrent liabilities – other | (140) | 2 | 21 | (117) |
| **Net commodity risk** | **$ 27** | **$ -** | **$ 90** | **$ 117** |

Gains and losses associated with price risk management activities were recorded as follows:

| | Commodity Risk | |
|---|---|---|
| | Three Months Ended March 31, | |
| (in millions) | 2016 | 2015 |
| Net unrealized gain (loss) - regulatory assets and liabilities [1] | $ (7) | $ (52) |
| Realized loss - cost of electricity [2] | (29) | (7) |
| Realized loss - cost of natural gas [2] | (1) | (1) |
| **Total commodity risk** | **$ (37)** | **$ (60)** |

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Condensed Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Condensed Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of th e major credit rating agencies. At March 31, 2016 , the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **December 31, 2015** |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (9) | $ (2) |
| Collateral posting in the normal course of business related to these derivatives | 7 | - |
| **Net position of derivative contracts/additional collateral posting requirements [1]** | **$ (2)** | **$ (2)** |

[1] This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

**NOTE 8: FAIR VALUE MEASUREMENTS**

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E C orporation and not the Utility.

| | Fair Value Measurements At March 31, 2016 | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Netting [1]** | **Total** |
| **Assets:** | | | | | |
| Short-term investments | $ 97 | $ - | $ - | $ - | $ **97** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 25 | - | - | - | **25** |
| Global equity securities | 1,619 | - | - | - | **1,619** |
| Fixed-income securities | 682 | 508 | - | - | **1,190** |
| Assets measured at NAV | - | - | - | - | **13** |
| **Total nuclear decommissioning trusts [2]** | **2,326** | **508** | **-** | **-** | **2,847** |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | 1 | 12 | 246 | 3 | **262** |
| Gas | 2 | 3 | - | (1) | **4** |
| **Total price risk management instruments** | **3** | **15** | **246** | **2** | **266** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 58 | - | - | **58** |
| Life insurance contracts | - | 72 | - | - | **72** |
| **Total rabbi trusts** | **-** | **130** | **-** | **-** | **130** |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | - | - | - | **8** |
| Assets measured at NAV | - | - | - | - | **147** |
| **Total long-term disability trust** | **8** | **-** | **-** | **-** | **155** |
| **Total assets** | **$ 2,434** | **$ 653** | **$ 246** | **$ 2** | **$ 3,495** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | $ 67 | $ 5 | $ 171 | $ (72) | $ **171** |
| Gas | - | 1 | - | - | **1** |
| **Total liabilities** | **$ 67** | **$ 6** | **$ 171** | **$ (72)** | **$ 172** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $ 331 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2015 Level 1 | Level 2 | Level 3 | Netting [(1)] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Short-term investments | $ 64 | $ - | $ - | $ - | **$ 64** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 36 | - | - | - | **36** |
| Global equity securities | 1,520 | - | - | - | **1,520** |
| Fixed-income securities | 694 | 521 | - | - | **1,215** |
| Assets measured at NAV | - | - | - | - | **13** |
| **Total nuclear decommissioning trusts [(2)]** | **2,250** | **521** | **-** | **-** | **2,784** |
| Price risk management instruments (Note 9 in the 2015 Form 10-K) | | | | | |
| Electricity | - | 9 | 259 | 18 | **286** |
| Gas | - | 1 | - | 1 | **2** |
| **Total price risk management instruments** | **-** | **10** | **259** | **19** | **288** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 57 | - | - | **57** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **127** | **-** | **-** | **127** |
| Long-term disability trust | | | | | |
| Short-term investments | 7 | - | - | - | **7** |
| Assets measured at NAV | - | - | - | - | **158** |
| **Total long-term disability trust** | **7** | **-** | **-** | **-** | **165** |
| **Total assets** | **$ 2,321** | **$ 658** | **$ 259** | **$ 19** | **$ 3,428** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9 in the 2015 Form 10-K) | | | | | |
| Electricity | $ 69 | $ 1 | $ 170 | $ (70) | **$ 170** |
| Gas | - | 2 | - | (1) | **1** |
| **Total liabilities** | **$ 69** | **$ 3** | **$ 170** | **$ (71)** | **$ 171** |

[(1)] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[(2)] Represents amount before deducting $3 14 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabi lities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of th e end of the reporting period. There were no material transfers between any levels for the three months ended March 31, 2016 and 2015 .

***Trust Assets***

*Assets Measured at Fair Value*

In general, investments held in the trusts are exposed to various risks, such as interest rate, cred it, and market volatility risks. N uclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at level 1.

Global e quity securities primarily include i nvestments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

*Assets Measured at NAV Using Practical Expedient*

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* and applied it retrospectively for the periods presented in their Condensed Consolidated Financial Statements . (See Note 2 above.) In accordance with this guidance, investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Condensed Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of US government securities and asset-backed securities.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk ma nagement utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from br okers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices . CRRs are classified as Level 3.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk m anagement function, which reports to the Chief Risk and Audit Officer of the Utility, is responsible for determining the fair value of the Utility's price risk manag ement derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 7 above.)

| (in millions) | Fair Value at At March 31, 2016 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Technique** | **Input** | **Range** [1] |
| Congestion revenue rights | $ 246 | $ 59 | Market approach | CRR auction prices | $ (23.81) - 8.76 |
| Power purchase agreements | $ - | $ 112 | Discounted cash flow | Forward prices | $ 17.64 - 38.80 |

[1] Represents price per megawatt-hour

| (in millions) | Fair Value at At December 31, 2015 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | **Technique** | **Input** | **Range** [1] |
| Congestion revenue rights | $ 259 | $ 63 | Market approach | CRR auction prices | $ (161.36) - 8.76 |
| Power purchase agreements | $ - | $ 107 | Discounted cash flow | Forward prices | $ 15.08 - 37.27 |

[1] Represents price per megawatt-hour

**Level 3 Reconciliation**

The following tables present the reconciliation for Level 3 price risk management instruments for the three months ended March 31, 2016 and 2015 :

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Asset (liability) balance as of January 1 | **$ 89** | **$ 69** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | (14) | (27) |
| **Asset (liability) balance as of March 31** | **$ 75** | **$ 42** |

[1] The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at March 31, 2016 and December 31, 2015 , as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at March 31, 2016 and December 31, 2015 .

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At March 31, 2016 | | At December 31, 2015 | |
|---|---|---|---|---|
| **(in millions)** | **Carrying Amount** | **Level 2 Fair Value** | **Carrying Amount** | **Level 2 Fair Value** |
| PG&E Corporation | $ 350 | $ 356 | $ 350 | $ 354 |
| Utility | 15,412 | 17,823 | 14,918 | 16,422 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| **(in millions)** | **Amortized Cost** | **Total Unrealized Gains** | **Total Unrealized Losses** | **Total Fair Value** |
|---|---|---|---|---|
| **As of March 31, 2016** | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 25 | $ - | $ - | $ 25 |
| Global equity securities | 603 | 1,038 | (9) | 1,632 |
| Fixed-income securities | 1,113 | 81 | (4) | 1,190 |
| **Total** [(1)] | **$ 1,741** | **$ 1,119** | **$ (13)** | **$ 2,847** |
| **As of December 31, 2015** | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 36 | $ - | $ - | $ 36 |
| Global equity securities | 508 | 1,034 | (9) | 1,533 |
| Fixed-income securities | 1,165 | 58 | (8) | 1,215 |
| **Total** [(1)] | **$ 1,709** | **$ 1,092** | **$ (17)** | **$ 2,784** |

[(1)] Represents amounts before deducting $ 331 million and $3 14 million at March 31, 2016 and December 31, 2015 , respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

| **(in millions)** | **As of March 31, 2016** |
|---|---|
| Less than 1 year | $ 26 |
| 1–5 years | 409 |
| 5–10 years | 251 |
| More than 10 years | 504 |
| **Total maturities of fixed-income securities** | **$ 1,190** |

The following table provides a summary of activity for the investments :

| | Three Months Ended | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **March 31, 2015** |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 439 | 417 |
| Gross realized gains on sales of securities held as available-for-sale | 5 | 35 |
| Gross realized losses on sales of securities held as available-for-sale | (2) | (3) |

**NOTE 9: CONTINGENCIES AND COMMITMENTS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to sup port its operating activities. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters.

**Enforcement and Litigation Matters**

***CPUC Matters***

*Order Instituting an Investigation into Compliance with Ex Parte Communication Rules*

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have been made or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker or a Commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in the CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices.

On April 18, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN , and the Utility filed a joint Meet and Confer Process Report in advance of the prehearing conference that was held on Apr il 20, 2016. The report included the proposed scope of the proceeding, including the number of communications at issue, a procedure for moving undisputed facts into the evidentiary record, a diligence process for providing additional factual information, and a procedural schedu le. Subject to the CPUC's approval, the parties have agreed that the scope of this proceeding may include a total of 159 communications (the 46 communications already included in the OII and 113 additional communications). The parties also recommended briefing on whether an additional 21 communications should be included in the proceeding. The Utility is expecting a ruling on these proposals in the second quarter of 2016.

The CPUC will determine whether the communications included within the scope of the proceeding were in violation of its rules and whether to impos e penalties or other remedies. The CPUC can impose fines up to $50,000 for each violation, per day. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this discretion in determining penalties.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII but they are unable to reasonably estimate the amount or range of future charges that could be incurred, because it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations, and whether the CPUC will consider additional communications in the OII, including those identified in a motion filed on December 1, 2015, by the City of San Bruno in the 2015 GT&S rate case . It is also uncertain whether the CPUC will take additional action in any of the proceedings in which the Utility has self-reported communications that may have violated the CPUC's ex parte rules.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office also have been investigating matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility .

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices with respect to maintaining safe operation of its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014.

On September 30, 2015, the SED submitted its supplemental testimony, which included incidents allegedly related to record-keeping that had not been identified in the initial order, and also asserted violations related to the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities.

On February 26, 2016, the Utility, the SED, TURN , and the City of Carmel , California ("Carmel") filed their opening briefs . In its brief, the SED cite d alleged record-keeping violations related to various natural gas distribution incidents, the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities. The SED recommend ed that the CPUC impose a fine on the Utility of approximately $112 million for these alleged viol ations. The SED also recommended that the CPUC require the Utility to undertake various remedial actions with respect to its gas distribution system records and facilities and that the Utility be prohibited from recovering remedial-related costs from customers. Carmel recommend ed that the CPUC impose penalties on the Utility of up to approximately $652 million, including approximately $137 million for the natural gas explosion that occurred in Carmel on March 3, 2014 (for which the Utility has previo usly paid a CPUC-imposed fine of $10.85 million). Carmel also recommended various remedial measures. TURN recommended that the Utility be required to undertake remedial actions, fund annual SED audits of the Utility's record-keeping practices for a period of ten years, and promptly correct any deficiencies identified in those audits.

On April 1, 2016, the Utility filed its reply brief in which the Utility indicated that it did not agree that any penalty was appropriate, but if the CPUC determined that a penalty should be imposed, such penalty s hould not exceed $33.6 million. The Utility recommended that such penalty, if imposed, should be invested in the safety of the Utility's gas distribution system, for example for implementation of certain rem edial measures. The Utility expects that the presiding officer's decision will be issued within 60 days of the April 1, 2016 filing. Unless any party files an appeal of the presiding officer's decision or a CPUC Commissioner requests a CPUC review of the presiding officer's decision within 30 days, the decision will become final. The CPUC has the authority to extend the deadlines indicated above.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the U tility in the form of fines or other remedies, including possible future unrecoverable costs to implement operational remedies. Remedies would be recorded in the period the expense is incurred and fines would be recorded when considered probable and their amount or range can be reasonably estimated. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred given the CPUC's discretion in imposing fines and other remedies.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. T he Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

*Potential Safety Citations*

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. In addition, the California utilities are required to inform the SED of self-identified or self-corrected violations of natural gas safety regulations. The CPUC has delegated authority to the SED to issue citations and impose fines for violations identified through audits, investigations, or self-reports. The SED can consider the discretionary factors discussed above (see " Order Instituting an Investigation into Compliance with Ex Parte Communication Rules" above) in determining the number of violations and whether to impose daily fines for continuing violations. The SED is required, however, to impose the maximum statutory penalty of $50,000 for each separate violation.

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The Utility believes it is probable that the SED will impose fines or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

***Federal Matters***

*Federal Criminal Indictment*

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that superseded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. Although the trial previously had been scheduled to begin on April 26, 2016, the court vacated the trial date and no new trial date has been set. The court stated that it will set a new trial date in due course.

The maximum statutory fine for each felony count is $500,000, for total potential fines of $6.5 million. The government is also seeking fines under the Alternative Fines Act. The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." On December 8, 2015, the court issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act. The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of gross gains prior to deciding whether to dismiss those allegations. Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million. On February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Condensed Consolidated Financial Statements as such amounts are not considered to be probable.

*Other Federal Matters*

T he Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. It is uncertain whether any additional charges will be brought against the Utility .

**Capital Expenditures R elating to Pipeline Safety Enhancement Pla n**

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of March 31, 2016, th e Utility has spent $1.3 billion on PSEP-related capital costs, of which $665 million was written off in previous years for costs that are expected t o exceed the authorized amount. The Utility expects the remaining PSEP work to co ntinue beyond 2016. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

**Penalty Decision's Disallowance of Natural Gas Capital Spend**

On Ap ril 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings pending against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "Penalty Decision") . (In January 2016, the CPUC closed the investigative proceedings.) The total penalty includes (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. In August 2015, the Utility paid the $300 million fine.

For the three months ended March 31, 2016, the Utility recorded additional charges in operating and maintenance expenses in the Condensed Consolidated Statements of Income of $87 million, as a result of the Penalty Decision. The cumulative charges at March 31, 2016, and the additional future charges to reach the $1.6 billion total are shown in the following table:

| (in millions) | Three Months Ended March 31, 2016 | Cumulative Charges March 31, 2016 | Future Charges and Costs | Total Amount |
|---|---|---|---|---|
| Fine paid to the state | $ - | $ 300 | $ - | $ 300 |
| Customer bill credit | - | 400 | - | 400 |
| Charge for disallowed capital (1) | 87 | 494 | 195 | 689 |
| Disallowed revenue for pipeline safety expenses (2) | - | - | 161 | 161 |
| CPUC estimated cost of other remedies (3) | - | - | - | 50 |
| **Total Penalty Decision fines and remedies** | **$ 87** | **$ 1,194** | **$ 356** | **$ 1,600** |

(1) The Penalty Decision disallows the Utility from recovering $850 million in costs associated with pipeline safety-related projects and programs th at the CPUC will identify in a final decision to be issued in th e Utility's 2015 GT&S rate case. The Penalty Decision requires that at least $689 million of the $850 million cost disallowance be allocated to capital expenditures. The Utility estimates that approximately $ 494 million of cumulative capital spending is probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.

(2) These costs are being expensed as incurred. Future GT&S revenues will be reduced for these unrecovered expenses.

(3) In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies spec ified in the Penalty Decision and does not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. These costs are being expensed as incurred.

**O ther Legal and Regulatory Contingencies**

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred.

***Investigation of the Butte Fire***

On April 28, 20 16, Cal Fire released its report of the investigation of the origin and cause of the "Butte fire," the wildfire that ignited and spread in Amador and Calaveras Counties in Northern California in September 2015. Cal Fire's repor t concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

In connection with the Butte fire, approximately 32 complaints have been filed to date against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving approximately 1,300 individual plaintiffs and their insurance companies. In response to plaintiffs' and the Utility's requests, the California Judicial Council has authorized the coordination of all cases in the Superior Court of California, Sacramento County. Plaintiffs have begun to present to the Utility claims seeking early resolution of preference cases (individuals who due to their age and/or physical condition are not likely to meaningfully participate in a t rial under normal scheduling). The number of complaints may increase in the future. An initial case management conference was held on April 22, 2016 and the next case management conference is currently scheduled for May 24, 2016.

In connection with this matter, the Utility may be liable for property damages without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent.

Based on the evidence described in the Cal Fire report that the Gray Pine tree contacted an electric line of the Utility, the Utility believes that it is probable that it will incur a loss of $350 million for property damages in connection with this matter, which corresponds to the lower end of the range of its reasonably estimated losses. This amount is based on estimates about the number, size, and type of structures damaged or destroyed, and assumptions about the contents of such structures and other property damage. The Utility currently is unable to reasonably estimate the upper end of the range. At March 31, 2016, the Condensed Consolidated Balance Sheets include $350 million in other current liabilities for the estimated property damages .

The Utility also believes that it is reasonably possible that it will incur a loss in exc ess of this amount , for additional costs related to fire suppression, personal injury damages , and other damages. The Utility believes that $90 million is a reasonable estimate of fire suppression costs. The Utility currently is unable to reasonably estimate other costs.

The Utility has insurance coverage for third party claims. If the amount of insurance is insufficient to cover the Utility's liability resulting from the Butte fire, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected.

As a result of the Cal Fire report, additional investigations and proceedings may be opened, the outcome of which PG&E Corporation and the Utility are unable to predict.

***Rehearing of CPUC Decisions Approving 2006 – 2008 Energy Efficiency Incentive Awards***

On September 17, 2015, the CPUC granted TURN's and ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California IOUs for the 2006-2008 en ergy efficiency program cycle. Under the incentive ratemaking mechanism applicable to the 2006-2008 program cycle, the Utility could have earned incentive revenues up to a maximum of $180 million, depending on the extent to which the Utility achiev ed the energy savings targets. Conversely, to the extent the Utility failed to achieve the targets, the Utility could have been required to offset future incentive earnings claims by amounts previously awarded, and, in addition, could have incurred p enalties of up to $180 million. The Utility was awarded a total of $104 million for the 2006-2008 program cycle. In the re-opened proceeding, the CPUC will evaluate whether the incentive amounts awarded to the IOUs were just and reasonable, and whether any refunds are due.

On March 18, 2016, TURN and ORA submitted a joint proposal to require a refund of incentive awards that TURN and ORA argue were not calculated in accordance with the ratemaking mechanism rules and procedures the CPUC had previously adopted . TURN and ORA contended that the CPUC should order the Utility to refund $104 million, the entire incentive earnings award, plus interest, to customer s as either (1) a revenue credit to customers' distribution and gas transportation accounts or (2) as a line item to the customers' first monthly bill following the issuance of a CPUC decision.

Additionally, on March 18, 2016, the IOUs submitted their proposals requesting that the CPUC reaffirm its prior decisions. The IOUs asserted that, given the many unresolved disputes about the data in the Energy Division's 2010 Evaluation Report, the CPUC appropriately used differen t data to calculate the awards. The IOUs noted that under the incentive ratemaking mechanism, any refunds of prior incentive earnings should be deducted from future incentive earnings claims.

On April 8, 2016, the IOUs, TURN and ORA filed comments on the proposals , in which the parties reiterated their requests. The Utility currently expects that evidentiary hearings, if ordered by the CPUC, would be held in July 2016. It is uncertain how the CPUC will resolve this matter and when the CPUC will issue a decision.

PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts previously awarded or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations. If the Utility were required to make a refund as TURN and ORA propose, PG&E Corporation's and the Utility's financial results would be affected by the amount of any refund-related charges.

***Residential Rate Reform Rate Change***

On February 17, 2016, the Utility filed a proposed rate change for rates to be billed to customers effective March 1, 2016. On February 29, 2016, the CPUC rejected the Utility's proposed rate change, stating that the rate design failed to comply with the requirements adopted in the Decision on Residential Rate Reform issued on July 3, 2015, that set a specific rate change "glidepath" for the Utility. The Utility began billing customers based on its proposed rates on March 1, 2016. On March 9, 2016, the assigned ALJ issued a ruling directing the Utility to show cause why the CPUC should not order sanctions and other remedies in response to the Utility charging rates not authorized by the CPUC. On March 14, 2016, the assigned ALJ issued an additional ruling that (1) acknowledged that utilities might not be able to follow the exact "glidepath" set forth in the decision because it had been based on forecast data and (2) indicated a new process to be followed before the CPUC if the new rates do not exactly match the "glidepath." On March 24, 2016, the Utility temporarily reverted back to billing customers based on rates generally similar to those in place prior to March 1, 2016. Also, on March 24, 2016, the Utility filed an additional advice letter proposing a new, three-tiered rate structure. The proposed new rate structure is subject to the CPUC approval. On April 20, 2016, the Energy Division of the CPUC issued a draft resolution that approves the Utility's proposed solution, but does not address the ruling to show cause. The Utility believes it is reasonably possible it may be subject to penalties or shareholder reparations for charging rates not authorized by the CPUC between March 1, 2016 and March 24, 2016. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred.

***Other Contingencies***

Accruals for other legal and regulatory contingencies (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters" and "Other Legal and Regulatory Contingencies" ) totaled $ 55 million at March 31 , 2016 and $ 63 million at December 31, 201 5 . These amounts are included in other current liabilities in the Condensed Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Environmental Remediation Contingencies**

The Utility's environmental remediation liability is primarily included in non-current liabilities on the Condensed Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **March 31, 2016** | **December 31, 2015** |
| Topock natural gas compressor station [(1)] | $ 302 | $ 300 |
| Hinkley natural gas compressor station [(1)] | 140 | 140 |
| Former manufactured gas plant sites owned by the Utility or third parties | 283 | 271 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites | 136 | 164 |
| Fossil fuel-fired generation facilities and sites | 103 | 94 |
| **Total environmental remediation liability** | **$ 964** | **$ 969** |

[(1)] See "Natural Gas Compressor Station Sites" below.

At March 31, 2016 , the Utility expected to recover $ 680 m illion of its environmental remediation liability through various ratemaking mech anisms authorized by the CPUC. Some of the Utility 's environmental remediation liability, such as the environmental remediation costs associated with the Hinkley site discussed below, will not be recove red in rates.

***Natural Gas Compressor Station Sites***

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as th e "Topock site." The Utility also is required to take measures to abate the effects of the contamination on the environment.

***Hinkley Site***

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. O n November 4, 201 5 , the Regional Board adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the po tential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires set ting plume capture requirements, requires establish ing a monitoring and reporting program , and finalizes deadlines for the Utility to meet interim cleanup targets.

The Utility's environmental remediation liability at March 31, 2016 reflects the Utility's best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final remediation plan and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

***Topock Site***

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California D epartment of T oxic S ubstances C ontrol and the U.S. Department of the Inter ior. I n November 201 5 , the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The DTSC is conducting an additional environmental review of the proposed design , and the Utility anticipates that the DTSC's draft environmental impact report will be issued for public comment in July 2016. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in December 2016. After the Utility modifies its design in response to the final report, the Utility plans to seek approval to begin construction of the new in-situ treatment system in early 2017.

The Utility 's environmental remediation liability at March 31 , 2016 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

***Reasonably Possible Environmental Contingencies***

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $ 1.9 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if th e other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations , future financial condition , and cash flows during th e period in which they are recorded.

**Nuclear Insurance**

In addition to the nuclear insurance the Ut ility maintains through the NEIL, the Utility also is a member of the EMANI , which provides excess insurance coverage for property damages and business interruption losses incurred by th e Utility if a nuclear or non- nuclear event were to occur at Diablo Canyon.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of April 1, 2016, the current maximum aggregate annual retrospective premium obligation for the Utility is approximately $60 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $2.1 million, as of April 1, 2016. For more information about the Utility's NEIL coverage, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

**Resolution of Remaining Chapter 11 Disputed Claims**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims agains t these electricity suppliers.

At December 31, 2015 , the Consolidated Balance Sheets reflected $ 454 million in net claims, within Disputed claims and customer refunds, and $ 228 million of cash in escrow for payment of the remaining net disputed claims, within Restricted cash. There were no significant changes to these balances during the three months ended March 31 , 2016 . However, on April 14, 2016, PG&E filed a Joint Offer of Settlement with the FERC requesting approval of a $256 million settlement agreement which, if approved, would result in a reduction to PG&E's net disputed claims liability.

**Tax Matters**

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of March 31, 2016 , it is reasonably possible that unrecognized tax benefits will decrease by approximately $ 70 million within the next 12 months . PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income .

**Purchase Commitments**

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. At December 31, 2015 t he Utility had undiscounted future expected obligations of approximately $50 billion. (See Note 1 3 of the Notes to the Consolidated Financ ial Statements in Item 8 of the 201 5 Form 10-K . ) The Utility has not entered into any new material commitments during the t hree months ended March 31, 2016 .

**ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

## OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, an d local governmental agencies.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. It should also be read in conjunction with the 201 5 Form 10-K.

**Summary of Changes in Net Income and Earnings per Share**

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS on an earnings from operations basis) compared to the same period in the prior year (see "Results of Operations" below). " Earnings from operations " is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. " Items impacting comparability " represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating plans, and employee incentive compensation . PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance . E arnings from operations are not a substitute or alternative for GAAP measures such as income av ailable for common shareholders and may not be comparable to similarly titled measures used by other companies.

| | Three Months Ended March 31, | |
|---|---|---|
| **(in millions, except per share amounts)** | **Earnings** | **EPS (Diluted)** |
| **Income Available for Common Shareholders - March 31, 2015** | **$ 31** | **$ 0.06** |
| Fines and penalties [1] | 369 | 0.77 |
| Pipeline-related expenses [2] | 10 | 0.02 |
| Legal and regulatory related expenses [2] | 8 | 0.02 |
| **Earnings from Operations -March 31, 2015 [3]** | **$ 418** | **$ 0.87** |
| Growth in rate base earnings | 26 | 0.05 |
| Timing of taxes [4] | (40) | (0.08) |
| Gain on disposition of SolarCity stock [5] | (14) | (0.03) |
| Increase in shares outstanding | - | (0.03) |
| Miscellaneous | 17 | 0.04 |
| **Earnings from Operations - March 31, 2016 [3]** | **$ 407** | **$ 0.82** |
| Butte fire related expenses [6] | (226) | (0.45) |
| Fines and penalties [1] | (51) | (0.10) |
| Pipeline-related expenses [2] | (13) | (0.03) |
| Legal and regulatory related expenses [2] | (10) | (0.02) |
| **Income Available for Common Shareholders - March 31, 2016** | **$ 107** | **$ 0.22** |

(1) R epresents the impact of the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements for before-tax amounts) .

(2) Represents pipeline-related expenses, including costs incurred to identify and remove encroachments from transmission pipeline rights of way and to perform remaining work under the Utility's PSEP which only occurred in 2015. Legal and regulatory related expenses include various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(3) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in No tes (1) and (2) .

(4) Represents the timing of taxes reportable in quarterly financial statements.

(5) Represents the gain recognized during the three months ended March 31, 2015. No comparable gain was recognized in 2016.

(6) For the three months ended March 31, 2016, the Utility incurred charges of $350 million, pre-tax, related to estimated property damages in connection with the Butte fire and $31 million, pre-tax, for Utility clean-up, repair, and legal costs associated with the Butte fire , for a total of $381 million, pre-tax.

**Key Factors Affecting Financial Results**

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materiall y affected by the following factors:

- *The Outcome of Enforcement, Litigation , and Regulatory Matters.* Future financial results will be impacted by the unrecoverable pipeline safety-related and remedies costs required by the Penalty Decision. (For more information about the Penalty Decision, see Note 9 of the Notes to the Condensed Conso lidated Financial Statements.) The Utility's future results may also be impacted by various other pending enforcement , litigation an d regulatory actions, including but not limited to those related to the federal criminal charges and CPUC investigations of the Utility's compliance with natural gas distribution facilities record-keeping practices, potential violations of the CPUC's ex parte communication rules , the re-hearing of the 2006-2008 energy efficiency incentive awards, and the Butte fire. (See "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- *The Timing and Out come of Ratemaking Proceedings.* The 2015 GT&S rate case remains pending. The Utility requested that the CPUC authorize a $532 million increase in annual revenue requirements for gas transmission and storage operations beginning on January 1, 2015 with attrition increases in 2016 and 2017. Any revenue requirement increase that the CPUC may authorize would be retroactive to January 1, 2015 but would be recorded in the period a final decision is reached. (See "Regulatory Matters − 2015 Gas Transmission and Storage Rate Case" below for more information.) In February 2016, the Utility updated its 2017 GRC application to req uest that the CPUC authorize a revenue requirement increase of $333 million for 2017 for the Utility's electric generation business and its electr ic and natural gas distribution businesses with attrition increases in 2018 and 2019. (See "Regulatory Matters − 2017 General Rate Case" below for more information.) The CPUC's decisions in these cases are expected to be issued in 2016. The outcome of regulatory proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- *The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures.* Whether the Utility is able to earn its authorized rate of return could be materially affected if the Utility's actual costs differ from the amounts authorized in the rate case decisions. In addition to incurring shareholder-funded costs and costs associated with remedial measures required by the Penalty Decision, the Utility also forecasts that in 2016 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. The ultimate amount of unrecovered costs also could be affected by how the CPUC determines which costs are included in determining whether the $850 million shareholder-funded obligation under the Penalty Decision has been met, and the outcome of pending and future investigations and enforcement matters. (See "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) The Utility's ability to recover costs in the future also could be affected by decreases in customer demand driven by legislative and regulatory initiatives relating to distributed generation resources, renewable energy requirements, and changes in the electric rate structure.

- *The Amount and Timing of the Utility's Financing Needs .* PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. F or the three months ended March 31, 2016, PG&E Corporation issued $ 152 million of common stock and used $ 65 million of the cash proceeds to make equity contributions to the Utility. PG&E Corporation forecasts that it will continue issuing a material amount of equity in 2016 and future years to support the Utility's capital expenditures. PG&E Corporation will issue additional equity to fund charges incurred by the Utility to comply with the Penalty Decision, to fund unrecoverable pipeline-related expenses, and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances would have a material dilutive impact on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1, Financial Statements and Supplementary Data, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in the 2015 Form 10-K and in Part II below under "Item 1A. Risk Factors . " In addition, t his quarterly r eport contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regard ing these events and management' s knowledge of facts as of the date of this report. See the section entitled "Cautionary Language Regarding Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new informati on, future events, or otherwise.

**RESULTS OF OPERATIONS**

**PG&E Corporation**

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The following table provides a summary of net income available for common shareholders for the three months ended March 31, 2016 and 2015 :

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| **(in millions)** | **2016** | | **2015** | |
| Consolidated Total | $ | 107 | $ | 31 |
| PG&E Corporation | | 2 | | 30 |
| Utility | $ | 105 | $ | 1 |

PG&E Corporation's net income primarily consists of interest expense on long-term d ebt, income taxes, and other income from investments. Results in 2015 include approximately $30 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation with no corresponding gains in 2016 .

**Utility**

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three months ended March 31 , 2016 and 2015 . The table separately identifies the r evenues and costs that impact ed earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) , and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized ( such as the payment of pension costs ) and the corresponding revenues the Utility is authorized to collect to recover such costs , do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

The Utility's operating results for the three months ended March 31 , 2016 and 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

| | Three Months Ended March 31, 2016 | | | Three Months Ended March 31, 2015 | | |
|---|---|---|---|---|---|---|
| | Revenues/Costs: | | | Revenues/Costs: | | |
| **(in millions)** | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
| Electric operating revenues | $ 1,933 | $ 1,199 | $ 3,132 | $ 1,786 | $ 1,228 | $ 3,014 |
| Natural gas operating revenues | 523 | 320 | 843 | 506 | 380 | 886 |
| **Total operating revenues** | **2,456** | **1,519** | **3,975** | **2,292** | **1,608** | **3,900** |
| Cost of electricity | - | 950 | 950 | - | 1,000 | 1,000 |
| Cost of natural gas | - | 222 | 222 | - | 274 | 274 |
| Operating and maintenance | 1,664 | 347 | 2,011 | 1,589 | 334 | 1,923 |
| Depreciation, amortization, and decommissioning | 696 | - | 696 | 631 | - | 631 |
| **Total operating expenses** | **2,360** | **1,519** | **3,879** | **2,220** | **1,608** | **3,828** |
| **Operating income** | **96** | **-** | **96** | **72** | **-** | **72** |
| Interest income [(1)] | | | 4 | | | 1 |
| Interest expense [(1)] | | | (201) | | | (187) |
| Other income, net [(1)] | | | 24 | | | 26 |
| Income (loss) before income taxes | | | (77) | | | (88) |
| Income tax benefit [(1)] | | | (185) | | | (92) |
| Net income | | | 108 | | | 4 |
| Preferred stock dividend requirement [(1)] | | | 3 | | | 3 |
| **Income Available for Common Stock** | | | **$ 105** | | | **$ 1** |

[(1)] These items impacted earnings for the three months ended March 31 , 2016 and 2015 .

**Utility Revenues and Costs that Impacted Earnings**

The following discussion presents the Utility's operating results for the three months ended March 31, 2016 and 2015 , focusing on revenues and expenses that impact ed earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased by $ 164 million , or 7% , in the three months ended March 31, 2016, compared to the same period in 2015 primarily due additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case.

The Utility has requested the CPUC authorize an increase to its revenue requirements for 2015, 2016, and 2017 in its GT&S rate case. It is unlikely that the Utility will be able to recognize an increase in its GT&S revenue until the second half 2016 or a later period during which a final decision is issued . The CPUC's decision in th is case is expected to be issued in 2016. (See "Ratemaking Proceedings" below.)

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings increased by $ 75 million, o r 5% , in the three months ended March 31, 2016 compared to the same period in 2015 primarily due to $381 million in charges related to the Butte Fire, approximately $ 90 million of other operating expenses, $34 million of higher disallowed capital charges related to the Penalty Decision , and $30 million of higher benefit-related expenses. This increase was offset by $500 million in charges associated with the Penalty Decision for fines and customer refunds incurred in the first quarter of 2015 with no corresponding charges in 2016. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

The Utility's future financial statements will continue to be impacted by additional charges associated with the Penalty Decision, costs related to the Butte Fire, and unrecoverable pipeline-related expenses. (See "Key Factors Affecting Financial Results" above and Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

*Depreciation, Amortization, an d Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased by $ 65 million , or 10% in the three months ended March 31, 2016 compared to the same period in 2015. This increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by CPUC in the 2014 GRC decision, which was first reflected in the third quarter of 2014, and by the FERC in the TO rate case.

*Interest Income, Interest Expense, and Other Income, Net*

There were no material changes to interest income , interest expense, and other income, net for the periods presented.

*Income Tax Benefit*

The income tax benefit increased by $ 93 million, or 101% in the three months ended March 31, 2016 as compared to the same period in 2015 . The effective tax rates for the three months ended March 31, 2016 and 2015 were 241% and 105%, respectively. These increases were primarily driven by benefits resulting from various tax audit results in the three months ended March 31, 2016 with no comparable amounts in the three months ended March 31, 2015 and the tax impact of a non-deductible penalty accrued in the three months ended March 31, 2015 with no comparable amount in the three months ended March 31, 201 6 .

**Utility Revenues and Costs that did not Impact Earnings**

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs. See below for more detail.

*Cost of Electricity*

The Utility's cost of electricity includes the costs of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

| | Three Months Ended March 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Cost of purchased power | $ 886 | $ 922 |
| Fuel used in own generation facilities | 64 | 78 |
| **Total cost of electricity** | **$ 950** | **$ 1,000** |
| Average cost of purchased power per kWh [1] | $ 0.104 | $ 0.099 |
| Total purchased power (in millions of kWh) [2] | 8,539 | 9,291 |

[1] Average cost of purchased power for the three months ended March 31, 2016 increased compared to the same period in 2015 primarily due to higher percentage of renewable energy resources. This increase was partially offset by lower market prices for natural gas.
[2] The decrease in purchased power resulted from an increase in generation from the Utility's own generation facilities. Hydroelectric and nuclear generation increased during the three months ended March 31, 201 6 as compared to the same periods in 201 5 .

The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including the Diablo Canyon nuclear generation power plant and hydroelectric plants), and the cost-effectiveness of each source of electricity.

*Cost of Natural Gas*

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

| | Three Months Ended March 31, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Cost of natural gas sold | $ 181 | $ 235 |
| Transportation cost of natural gas sold | 41 | 39 |
| **Total cost of natural gas** | **$ 222** | **$ 274** |
| Average cost per Mcf [1] of natural gas sold [2] | $ 2.26 | $ 3.26 |
| Total natural gas sold (in millions of Mcf) [1] | 80 | 72 |

[1] One thousand cubic feet

[2] Average cost of natural gas sold primarily impacted by a decline in the market price of natural gas in the three months ended March 31, 2016 compared to the same period in 2015 .

*Operating and Maintenance Expense s*

The Utility's operating expenses also include certain recoverable costs that the Utility incurs as part of its operations such as pension contributions and public purpose programs costs. If the Utility were to spend over authorized amounts, these expenses could have an impact on earnings.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its debt financing costs. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends, primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and borrowings and repayments under its revolving credit facility. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's equity contributions to the Utility are funded primarily t hrough common stock issuances. PG&E Corporation forecasts that it will issue between $600 million and $800 million in common stock during 2016, primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by charges incurred to comply with the Penalty Decision, by the timing and outcome of the 2015 GT&S rate case, by unrecover able pipeline-related expenses , and by fines and penalties that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" below. Common stock issuances by PG&E Corporation to fund these needs would have a material dilutive impact on PG&E Corporation's EPS.

### Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceedings under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 9 of the Notes to the Condensed Cons olidated Financial Statements.) The Utility is uncertain when and how the remaining disputed claims will be resolved.

### Financial Resources

#### *Debt and Equity Financings*

During the three months ended March 31, 2016, PG&E Corporation sold 1.3 million shares under its February 2015 equity distribution agreement for cash proceeds of $ 74 million, net of commissions paid of $ 1 million. As of March 31, 2016, the remaining gross sales av ailable under this agreement were $ 350 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the three months ended March 31, 2016, 2.3 million shares were issued for cash proceeds of $ 72 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility. For the three months ended March 31, 2016, PG&E Corporation made equity contributions to the Utility of $ 65 million.

In March 2016 , the Utility issued $ 6 00 million principal amount of 2.95 % Senior Notes due March 1, 2026. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper. In addition, in March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017 . The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

***Revolving Credit Facilities and Commercial Paper Program***

At March 31, 2016, PG&E Corporation and the Utility had $ 300 million and $ 2.5 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements . )

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At March 31, 2016, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51 % and 50 %, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At March 31, 2016, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

***Dividends***

In February 2016, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $ 226 million, of which approximately $ 221 million was paid on April 15, 2016, to shareholders of record on March 31 , 2016.

In February 2016, the Board of Directors of the Utility declared a common stock dividend of $179 million that was paid to PG&E Corporation on February 19 , 2016.

In February 2016, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on May 15 , 2016, to shareholders of record on April 29, 2016 .

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Three Months Ended March 31, 2016 | | | |
|---|---|---|---|---|
| **(in millions)** | **2016** | | **2015** | |
| Net cash provided by operating activities | $ | 1,063 | $ | 1,101 |
| Net cash used in investing activities | | (1,250) | | (1,272) |
| Net cash provided by financing activities | | 172 | | 166 |
| **Net change in cash and cash equivalents** | **$** | **(15)** | **$** | **(5)** |

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During the three months ended March 31, 2016, net cash provided by operating activities de creased by $ 38 million compared to th e same period in 2015. This de crease was primarily due to fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

Future cash flow from operating activities will be affected by various factors, including:

- the shareholder-funded bill credit of $400 million to natural gas customers in 2016, as required by the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and amounts of other fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement and litigation matters (see Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case and the 2017 GRC;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system (including costs to implement remedial measures and $850 million to pay for designated pipeline safety projects and programs, as required by the Penalty Decision);
- the timing and amount of tax payments (including the bonus depreciation), tax refunds, net collateral payments, and interest payments; and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

***Investing Activities***

Net cash used in investing activities de creased by $ 22 million during the three months ended March 31, 2016 as compared to the same period in 2015. The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $5. 6 billion in capital expenditures in 2016 and between $ 5.4 billion and $ 6.5 billion in 2017.

***Financing Activities***

During the three months ended March 31, 2016 , net cash provided by financing activities increased by $ 6 million compared to the same period in 2015. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

**ENFORCEMENT AND LITIGATION MATTERS**

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 9 in the Condensed Consolidated Financial Statements. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2015 Form 10-K and Part II. Other Information, Item 1. Legal Proceedings . Significant regulatory developments that have occurred since the 2015 Form 10-K was filed with the SEC are discussed below.

***Department of Interior Inquiry***

In September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the allegations contained in the superseding federal criminal indictment discussed in Note 9 of the Notes to the Condensed Consolidated Financial Statements.   The Utility filed its initial response on November 2, 2015 to demonstrate that it is a presently responsible contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate.  On April 8, 2016, the Utility received a series of follow-up questions from the DOI regarding the Util ity's November 2015 submission.  The DOI has not yet set a timeline for the Utility's response to th e questions.  It is uncertain when or if further action will be taken by DOI following the Utility's response.

***Litigation Related to the San Bruno Accident and Natural Gas Spending***

As of March 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

On February 27 , 2016, a new shareholder derivative complaint, *Bushkin v. Rambo et al* ., was filed in the United States District Court for the Northern District of California.  This complaint has been designated by the plaintiff as related to the pending shareholder derivative suit *Iron Workers Mid-South Pension Fund v. Johns, et al.* , discussed below.  The *Bushkin* complaint seeks to hold certain individual defendants responsible on claims of breach of fiduciary duty for damage to the company caused by the San Bruno accident, as well as by an alleged obstruction of the NTSB's investigation into the San Bruno accident and an alleged false statement related to PG&E Corporation's corporate governance practices in its 2015 Proxy Statement .  A case management conference o n this matter is currently set for June 17, 2016.

A case management conference in the *Iron Workers* action pending in the United States District Court for the Northern District of California is currently set for June 3, 2016.  Aside from the June 3, 2016 case management conference, t he case has been stayed pending conclusion of the federal criminal proceedings against the Utility.  As previously disclosed, on December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County , ordering the Court to stay all proceedings in the four consolidated *San Bruno Fire Derivative Cases* pending conclusion of the federal criminal proceedings against the Utility.

A cas e management conference in the action entitled *Tellardin v. PG&E Corp. et al.,* also pending in the Superior Court of California, San Mateo County, is currently set for August 9, 2016.  PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

## R EGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. Significant regulatory developments that have occurred since the 2015 Form 10-K was filed with the SEC are discussed below.

**2017 General Rate Case**

In the 2017 GRC, the Utility has requested that the CPUC determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. (The Utility's revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.)

The Utility's supplemental testimony filed on February 22, 2016, reduced the Utility's previously requested 2017 revenue requirement increase of $457 million (as compared to the 2016 authorized amount of $7.9 billion) to $333 million, representing a $124 million reduction from the previous request. The requested increase for 2018 was reduced from $489 million to $469 million, and the requested increase for 2019 was reduced from $390 million to $368 million. The Utility reduced its requested increase primarily to reflect the impact of the five-year extension of the federal tax code provisions regarding bonus depreciation, as well as the tax-deductibility of repair costs.

On April 8, 2016, ORA submitted its testimony. For 2017, instead of the Utility's requested increase, ORA recommended an $85 million reduction (approximately 1.1%) from the Utility's currently authorized 2016 revenue requirement. For 2018 and 2019, ORA proposed increases of $274 million and $283 million, respectively (representing an approximately 3.5% annual increase), significantly below the Utility's requested attrition increases of $469 million and $368 million, respectively. ORA also recommended to extend the GRC cycle another year and recommends a 2020 increase of $294 million (a 3.5% increase).

On April 29, 2016, TURN and several other intervening parties filed their testimonies. While TURN's proposal does not include a revenue requirement recommendation for 2017, TURN recommended significant reductions to 2017 forecast operating expense, capital expenditures and other items. For 2018 and 2019, TURN presented a revenue requirement increase proposal of $469 million (representing an approximately 5.9% annual increase) and $250 million (representing an approximately 3.0% annual increase), respectively.

The table below summarizes the differences between the Utility's revenue requirement increase proposal (based on the February 22, 2016 update), and ORA's and TURN's recommendations:

| | | ORA's Recommendation (in millions) | | TURN's Recommendation (in millions) | |
|---|---|---|---|---|---|
| Year | Utility's Proposal (in millions) | Increase / (Decrease) | Difference [1] (Decrease) | Increase / (Decrease) | Difference Increase/(Decrease) |
| 2017 | $ 333 | $ (85) | $ (418) | $ N/A [2] | $ N/A |
| 2018 | 469 | 274 | (195) | 469 | - |
| 2019 | 368 | 283 | (85) | 250 | (118) |
| 2020 | N/A | 294 [3] | N/A | N/A | N/A |

[1] Reflects the difference between the Utility's proposal and the recommendation.
[2] TURN's proposal does not include a revenue requirement recommendation for 2017.
[3] Reflects ORA's recommendation to extend the GRC cycle another year.

For 2017, ORA accepted the Utility's capital expenditure forecasts in most lines of business. The reduction proposed by ORA is primarily related to operating expenses. ORA recommended reductions in programs across all major lines of business, including programs such as gas leak survey frequency, gas record consolidation, information technology programs, electric operations and automation, hydroelectric programs, residential rate reform education and outreach (ORA recommended that these costs be tracked in a memorandum account), and enterprise records and information management. ORA also recommended reductions in administrative and general expenses, employee incentive compensation and benefits, as well as general business expenses, such as insurance. ORA's recommended capital reductions for 2015, 2016, and 2017 would result in a rate base reduction of nearly $200 million in 2017 compared to the Utility's 2017 forecast of $24.5 billion in the GRC lines of business.

For 2017, TURN recommended significant reductions to forecast operating expense, capital expenditures and other items across the major lines of business. TURN recommended reductions in gas programs, including pipeline replacement, replacement of gas services; electric programs, including new business and substation equipment replacement and grid modernization programs; customer service programs; and real estate programs. TURN also recommended reductions in administrative and general expenses, as well as employee incentive compensation and benefits. For 2017, TURN's recommended reductions in operating expense and capital expenditures amount to approximately $166 million and $733 million, respectively.

The following table shows the difference between the Utility's requested increases in 2017 revenue requirements (based on the February 22, 2016 update) and ORA's recommended amounts by line of business:

| **(in millions)<br>Line of Business:** | | **Utility's Proposal** | | | | **ORA's Recommendation Increase / (Decrease)** [(1)] | | | | **Difference** [(1) (2)]<br>**Increase / (Decrease)** |
|---|---|---|---|---|---|---|---|---|---|---|
| Electric distribution | $ | 71 | 1.7 | % | $ | (146) | (3.5) | % | $ | (217) |
| Gas distribution | | 63 | 3.6 | | | (59) | (3.4) | | | (122) |
| Electric generation | | 199 | 10.1 | | | 119 | 6.1 | | | (80) |
| **Total revenue requirements** | **$** | **333** | **4.2** | **%** | **$** | **(85)** | **(1.1)** | **%** | **$** | **(418)** |

[(1)] Certain amounts have been rounded.
[(2)] Reflects the difference between the Utility's proposal and the recommendation.

TURN did not present revenue requirement recommendations by line of business.

In addition, 11 other parties provided recommendations. The Alliance for Nuclear Responsibility recommended for the Utility's Diablo Canyon nuclear power plant an annual filing on the Utility's plans to extend the license, a new performance-based ratemaking measure and various disallowances. The Coalition of California Utility Employees, which represents the International Brotherhood of Electrical Workers, recommended increasing funding for gas operations (such as for pipe replacement and leak survey frequency) and for electric operations (such as for fault location isolation and services restoration, also known as FLISR, overhead fuses, poles, and cable), and reducing depreciation expense for gas mains and poles. Other parties made various other recommendations regarding investments in connection with electric reliability, leak management practices, safety, executive compensation, customer outreach, local office closures, and supplier and employee diversity.

The following tables show the Utility's currently requested amounts compared to 2016 authorized amounts:

| (in millions)<br>**Line of Business:** | | **Amounts Requested** | | **Amounts Currently Authorized For 2016** | | **Increase Compared to Currently Authorized Amounts** |
|---|---|---|---|---|---|---|
| Electric distribution | $ | 4,284 | $ | 4,213 | $ | 71 |
| Gas distribution | | 1,804 | | 1,741 | | 63 |
| Electric generation | | 2,161 | | 1,962 | | 199 |
| **Total revenue requirements** | **$** | **8,249** | **$** | **7,916** | **$** | **333** |

| **Cost Category:**<br>(in millions) | | | | | | |
|---|---|---|---|---|---|---|
| Operations and maintenance | $ | 1,833 | $ | 1,664 | $ | 169 |
| Customer services | | 367 | | 319 | | 48 |
| Administrative and general | | 975 | | 1,011 | | (36) |
| Less: Revenue credits | | (140) | | (131) | | (9) |
| Franchise fees, taxes other than income, and other adjustments | | 184 | | 37 | | 147 |
| Depreciation (including costs of asset removal), return, and income taxes | | 5,030 | | 5,016 | | 14 |
| **Total revenue requirements** | **$** | **8,249** | **$** | **7,916** | **$** | **333** |

According to the CPUC's procedural schedule, rebuttal testimonies are scheduled to be submitted by the Utility and other parties on May 27, 2016. Evidentiary hearings are to be held this summer, followed by a proposed decision to be released in November 2016 and a final CPUC decision to be issued in December 2016. On March 17, 2016, the CPUC issued a decision to allow the authorized revenue requirement changes to become effective on January 1, 2017, even if the final decision is issued after that date.

**2015 Gas Transmission and Storage Rate Case**

In the 2015 GT&S rate case, the Utility requested that the CPUC authorize a 2015 revenue requirement of $1.263 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $532 million over currently authorized amounts. The Utility also requested attrition increases of $83 million in 2016 and $142 million in 2017. The Utility requested that the CPUC authorize the Utility's forecast of its 2015 weighted average rate base for its gas transmission and storage business of $3.44 billion, which includes capital spending above authorized levels for the prior rate case period.

ORA has recommended a 2015 revenue requirement of $1.044 billion, an increase of $329 million over authorized amounts. TURN recommended that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service after January 1, 1956, as well as certain other work that TURN considers to be remedial. TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of capital expenditures during this period be subject to a reasonableness review and an independent audit. TURN stated that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit.

The Utility also has proposed changes to the revenue sharing mechanism authorized in the last GT&S rate case (covering 2011-2014) that subjected a portion of the Utility's transportation and storage revenue requirement to market risk. The Utility proposed full balancing account treatment that allows for recovery of the Utility's authorized transportation and storage revenue requirements (except for the revenue requirement associated with the Utility's 25% interest in the Gill Ranch storage field).

Based on the scoping ruling and procedural schedule that was issued on June 11, 2015, the CPUC plans to issue an initial decision to authorize revenue requirements followed by a second decision to reduce the authorized revenue requirements by the costs of designated safety-related projects and progr ams of $850 million cost disallowance i mposed by the Penalty Decision. (See Note 9 in the Condensed Consolidated Financial Statements for more information abou t the CPUC's Penalty Decision.) (In accordance with an earlier CPUC decision regarding the Utility's violation of the CPUC's ex parte communication rules made in the GT&S rate case, the first decision could disallow the Utility from recovering up to a five-month portion of the revenue increase that may o therwise have been authorized.) The second CPUC decision is expected to identify the costs that are counted toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC.

The authorized revenue requirements in the 2015 GT&S rate case would be retroactive to January 1, 2015 but would be recorded in the peri od a final decision is issued. Both decisions are anticipated in 2016.

**CPUC Cost of Capital Decision**

On February 25, 2016, the CPUC issued a decisio n granting a petition for modification filed by the Utility and the other two California investor-owned electric utilities to clarify that the CPUC's previously adopted cost of capital adjustment mechanism would not be triggered before their 2018 cost of capital applications are due on April 20, 2017. As a result, the Utility's currently authorized return on equity of 10.40% and capital structure, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock, will remain the same for 2017.

**Asset Retirement Obligations**

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP . On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC in its 2015 NDCTP . The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion, for a total estimated cost of $4.8 billion, due to increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

On April 4, 2016, TURN and ORA submitted protes ts to the Utility's 2015 NDCTP. TURN indicated that it intends to thoroughly review the Utility's power plants cost estimate to determine overall reasonableness of the Utility's request and that the Utility should be required to provide an alternative assessment of decommissioning costs and funding requirements if the Diablo Canyon license is renewed. ORA requested an evidentiary hearing to develop a full and complete record of the support and justification for the Ut ility's 2015 NDCTP application. On April 14, 2016, the Utility filed its resp onse and objected to TURN 's proposal for an alternate assessment of Diablo Canyon costs.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.3 billion at March 31, 2016, which includes an $818 million adjustment to reflect the increased cost estimates described above, and $2.5 billion at December 31, 2015. These estimates are based on the 20 16 decommissioning cost studies prepared in accordance with the CPUC requirements. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

**CPUC Investigation of the Utility's Safety Culture**

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report co ntaining the SED's assessment. The consultant ' s work is expected to begin in the second quarter of 2016.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned Commissioner will determine the scope of and next actions in the proceeding. The timing scope and potential outcome of the investigation are uncertain.

**Rehearing of CPUC Decisions Approving 2006 – 2008 Energy Efficiency Incentive Awards**

On September 17, 2015, the CPUC granted TURN's and ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California IOUs for the 2006-2008 energy efficiency program cycle. Under the incentive ratemaking mechanism applicable to the 2006-2008 program cycle, the Utility could have earned incentive revenues up to a maximum of $180 million, depending on the extent to which the Utility achieved the energy savings targets. Conversely, to the extent the Utility failed to achieve the targets, the Utility could have been required to offset future incentive earnings claims by amounts previously awarded, and, in addition, could have incurred penalties of up to $180 million . The Utility was awarded a total of $104 million for the 2006-2008 program cycle. In the re-opened proceeding, the CPUC will evaluate whether the incentive amounts awarded to the IOUs were just and reasonable, and whether any refunds are due.

On March 18, 2016, TURN and ORA submitted a joint proposal to require the refund of incentive awards that TURN and ORA argue were not calculated in accordance with the ratemaking mechanism rules and procedures the CPUC had previously adopted. TURN and ORA contended that the CPUC should order the Utility to refund $104 million, the entire incentive earnings award, plus interest, to customer s as either (1) a revenue credit to customers' distribution and gas transportation accounts or (2) as a line item to the customers' first monthly bill following the issuance of a CPUC decision.

Additionally, on March 18, 2016, the IOUs submitted their proposals requesting that the CPUC reaffirm its prior decisions. The IOUs asserted that, given the many unresolved disputes about the data in the Energy Division's 2010 Evaluation Report, the CPUC appropriately used different data to calculate the awards. The IOUs noted that under the incentive ratemaking mechanism, any refunds of prior incentive earnings should be deducted from future incentive earnings claims.

On April 8, 2016, the IOUs, TURN and ORA filed comments on the proposals, in which the parties reiterated their requests. The Utility currently expects that evidentiary hearings, if ordered by the CPUC, would be held in July 2016. It is uncertain how the CPUC will resolve this matter and when the CPUC will issue a decision.

PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts previously awarded or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations. If the Utility were required to make a refund as TURN and ORA propose, PG&E Corporation's and the Utility's financial results would be affected by the amount of any refund-related charges.

**OTHER MATTERS**

**Agreement with TransCanyon, LLC for Competitive Transmission Opportunities**

On March 29, 2016, the Utility entered into an agreement with TransCanyon, LLC, a joint venture between subsidiaries of Berkshire Hathaway Energy and Pinnacle West Capital Corporation, to jointly pursue competitive transmission opportunities solicited by the CAISO , the operator for the majority of the California electr ic transmission grid. The Utility and TransCanyon intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own an d operate transmission projects approved by the CAISO .

**LEGISLATIVE AND REGULATORY INITIATIVES**

The California Legislature and the CPUC have adopted requirements and policies to accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles, promote customer energy efficiency and demand response programs , and implement new state law requirements applicable to natural gas storage facilities . In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. Significant developments that have occurred since the 2015 Form 10-K was filed with the SEC are discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

*Electric Distribution Resources Plan*

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of distributed energy resources. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable a nd affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable an d affordable electric service. The Utili ty's 2017 GRC includes a request to recover some of the investment costs that it forecasts it will incur under its proposed electric distribution resources plan.

*Integrated Distributed Energy Resources Pilot Program*

On April 4, 2016, the assigned CPUC Commissioner and ALJ issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective distributed energy resources ("DERs"). The ruling assumes that the incentive would take the form of an additional payment to the utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The exact figure would be determined later if the proposal or a similar alternative is adopted by the CPUC. The ruling also states that it does not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities. Co mments on the proposal are due May 9 , 2016 a nd reply comments are due May 23 , 2016.

*Electric Rate Reform and Net Energy Metering*

On July 3, 2015, the CPUC approved a final decision to authorize the California IOUs to gradually flatten their tiered residential electric rate structures from four tiers to two tiers by January 1, 2019. The decision approved increased minimum bill charges for residential customers and also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential electric customers based on time-of-use rates (known as "default time-of-use rates") unless customers elect otherwise. The Utility also may propo se to impose a fixed charge on residential electric c ustomers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge in electric rates .

In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates are expected t o become effective for new NEM customers later in 2016. New NEM customers will be required to pay an interconnection fee, will be charged on time -of- use rates, and will be required to pay non-bypassable charges to hel p fund some of the costs of low- income, energy efficiency, and other programs that other customers pay. On March 7, 2016, the Utility and certain other parties, including TURN and CUE, filed applications for rehearing. The Utility requested that the CPUC vacate its January 2016 decision that the Utility asserts contains legal and factual errors. Many parties argued that the CPUC failed to complete its duties under AB 327, which required the CPUC to evaluate the costs and benefits of NEM.

*Electric Vehicle (EV) Infrastructure Development*

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing an EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain more than 25,000 EV charging stations and the associated infrastructure. The Utility proposed to engage with third-party EV service providers to operate and maintain the charging stations. The Utility requested that the CPUC approve forecasted capital expenditures of $551 million over the 5-year deployment period.

On September 4, 2015, the assigned CPUC Commissioner and the ALJ issued a scoping memo and procedural schedule that required the Utility to supplement its application by submitting a more phased deployment approach that will be considered in a first phase of the proceeding. On October 12, 2015, the Utility submitted supplemental testimony presenting two separate proposals. In its first proposal, the Utility has requested that the CPUC approve approximately $70 million in capital expenditures to deploy and own 2,510 EV charging station s over approximately 2 years. In its second proposal, the Utility has requested that the CPUC approve approximately $187 million in capital expenditures to deploy and own 7,530 EV charging stations over approximately 3 years.

On March 21, 2016, the Utility filed with the CPUC a settlement agreement that it entered into with certain parties, including environmental advocates, automakers, electric vehicle drivers, labor, and environmental justice advocates, that makes adjustments to the Utility's second proposal, including a reduction to requested capital expenditures to approximately $132 million. (TURN, ORA , and certain equipment suppliers are not parties to the agreement and filed responses on April 12, 2016, ge nerally opposing the settlement.) The settlement agreement is subject to approval by the CPUC. H earings were held in April 2016 and under the CPUC's schedule, a proposed decision for the first phase of the proceeding is expected to be issued in the third quarter of 2016. Further deployment of EV charging stations would be considered in a second phase of the proceeding depending on the outcome of the first phase.

**ENVIRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes , such as groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations ; the reporting and reduction of carbon dioxide and other greenhouse gas emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fue l. (See Note 9 of the N otes to the Condensed Consolidated Financial Statements , as well as "Item 1A. Risk Factors" and Note 13 in the 2015 Form 10-K.)

**CONTRACTUAL COMMITMENTS**

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that relate to purchases of electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and purchases of fuel and transportation to support the Utility's generation activities. (See " Purchase Commitments" in Note 9 of the Notes to the Condensed Consolidated Financial Statements). Contractual commitments that relate to financing arrangements include long-term debt, preferred stock, and certain forms of regulatory financing. For more in-depth discussion about PG&E Corporation's and the Utility's contractual commitments, see "Liquidity and Financial Resources" above and Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Commitments in the 201 5 Form 10-K.

**Off-Balance Sheet Arrangements**

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources , other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K (the Utility's commodity purchase agreements) .

**RISK MANAGEMENT ACTIVITIES**

PG&E Corporation , mainly through its ownership of the Utility, and the Utility are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for elect ricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances and offset credits, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "pric e risk" and "interest rate risk. " The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost vola tility, and manage cash flows. T he Utility uses derivative instruments only for non-trading purposes ( i.e ., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. These activities are discussed in detail in the 2015 Form 10-K. There were no significant developments to the Utility and PG&E Corporation 's risk management activities during the three months ended March 31 , 2016 .

**CRITICAL ACCOUNTING POLICIES**

The preparation of the Condensed Consolidated Financial Sta tements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, asset retirement obligations, and pension and other postretirement benefits plans to be critical accounting policies. These policies are considered critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of ma terial judgments and estimates. Actual results may differ materially from these estimates. These accounting policies and their key characteristics are discussed in detail in the 2015 Form 10-K .

**ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED**

See the discussion above in Note 2 of the Notes to the Condensed Consolidated Financial Statements.

## CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings ; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

the timing and outcomes of the 2015 GT&S rate case, the 2017 GRC, the TO rate cases, and other ratemaking and regulatory proceedings;

the timing and outcomes of the federal criminal prosecution of the Utility, the pending CPUC investigation of the Utility's natural gas distribution record-keeping practices, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and the other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

the timing and outcome of the CPUC's investigation of communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other ratemaking proceedings;

the outcome of the Butte fire litigation, and whether the Utility's insurance is sufficient to cover the Utility's liability resulting therefrom , or if insurance is otherwise available; and whether additional investigations and proceedings will be opened

whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the criminal prosecution of the Utility, the state and federal investigations of natural gas incidents, matters relating to the indicted case, improper communications between the CPUC and the Utility; and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

whether the Utility can control its costs within the authorized levels of spending, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;

the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

the outcomes of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security;

the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California;

the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies, including the California State Water Resources Board and the California State Lands Commission, that may affect the Utility's ability to continue operating Diablo Canyon; and whether the Utility decides to resume its pursuit to renew the two Diablo Canyon NRC operating licenses, and if so, whether the licenses are renewed;

the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; and whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and whether the amount of insurance is sufficient to cover the Utility's liability;

how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations, and whether the Utility is able to timely recover its associated investment costs;

whether the Utility's climate change adaptation strategies are successful;

the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on eq uity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services;

the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's information technology and operating systems;

the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the criminal prosecution, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see "Risk Factors" in the 2015 Form 10-K and in Part II, Item. 1A. Risk Factors below . PG&E Corporation and the Utility do not undertake an y obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## ITEM 3. QUANTITATIVE AND QUALITATIV E DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. (See the section above entitled "Risk Management Activities" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.)

## ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of March 31, 2016 , PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended March 31, 2016 , that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

## PART II. OTHER INFORMATION

## ITEM 1. LEGAL PROCEEDINGS

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 9 of the Notes to the Condensed Consolidated Financial Statement and Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, "Enforcement and Litigation Matters."

**Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission**

For a description of this matter, see " Part I, Item 3. Legal Proceedings " in the 2015 Form 10-K , the discussion of the Penalty Decision in Note 13 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K, and the discussion included in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

**Federal Criminal Indictment**

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that superseded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts , leaving 13 remaining counts. Although the trial previously had been scheduled to begin on April 26, 2016, the court vacated the trial date and no new trial date has been set. The court stated that it will set a new trial date in due course.

The maximum statutory fine for each felony count is $500,000, for total potential fines of $6.5 million. The government is also seeking fines under the Alternative Fines Act. The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." On December 8, 2015, the court issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act. The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of gross gains prior to deciding whether to dismiss those allegations. Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million. On February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Condensed Consolidated Financial Statements as such amounts are not considered to be probable.

For description of this matter, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K, the section entitled "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 in the 2015 Form 10-K, and the section entitled "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

**Litigation Related to the San Bruno Accident and Natural Gas Spending**

As of March 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

On February 27 , 2016, a new shareholder derivative complaint, *Bushkin v. Rambo et al* ., was filed in the United States District Court for the Northern District of California. This complaint has been designated by the plaintiff as related to the pending shareholder derivative suit *Iron Workers Mid-South Pension Fund v. Johns, et al.* , discus sed below. The *Bushkin* complaint seeks to hold certain individual defendants responsible on claims of breach of fiduciary duty for damage to the company caused by the San Bruno accident, as well as by an alleged obstruction of the NTSB's investigation into the San Bruno accident and an alleged false statement related to PG&E Corporation's corporate governance practic es in its 2015 Proxy Statement. A case management conference on this matter is currently set for June 17, 2016.

A case management conference in the *Iron Workers* action pending in the United States District Court for the Northern District of California is c urrently set for June 3, 2016. Aside from the June 3, 2016 case management conference, t he case has been stayed pending conclusion of the federal criminal proceedings against the Utility. As previously disclosed, on December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County , ordering the Court , to stay all proceedings in the four consolidated *San Bruno Fire Derivative Cases* pending conclusion of the federal criminal proceedings against the Utility.

A case management conference in the action entitled *Tellardin v. PG&E Corp. et al.,* also pending in the Superior Court of California, San Mateo County, is cur rently set for August 9, 2016.

For additional information regarding these matters, see the discussion entitled "Enforcement and Litigation Matters" above in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations. In addition, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Investigation of the Butte Fire**

On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the "Butte fire," the wildfire that ignited and spread in Amador and Calaveras Counties in Northern California in September 2015. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

In connection with the Butte fire, approximately 3 2 complaints have been filed to date against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving approximately 1,300 individual plaintiffs and their insurance companies. In response to plaintiffs' and the Utility's requests, the California Judicial Council has authorized the coordination of all cases in the Superior Court of California, Sacramento County. Plaintiffs have begun to present to the Utility claims seeking early resolution of preference cases (individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling). The number of complaints may increase in the future. An initial case management conference was held on April 22, 2016 and the next case management conference is currently scheduled for May 24, 2016.

In connection with this matter, the Utility may be liable for property damages without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent.

As a result of the Cal Fire report, additional investigations and proceedings may be opened, the outcome of which PG&E Corporation and the Utility are unable to predict.

For additional information, see Note 9 of the Notes to the Condensed Consolidated Financial Statements and Item 1A. Risk Factors.

**Other Enforcement Matters**

In addition, fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, investigations that were commenced after a pipeline explosion in Carmel, California on March 3, 2014, and other enforcement matters. See the discussion entitled "Enforcement and Litigation Matters" above in Part 1, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Diablo Canyon Nuclear Power Plant**

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board and the Utility, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Venting Incidents in San Benito County**

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called "pigs" that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline is released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility's transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County District Attorney notified the Utility in December 2014 that it was contemplating bringing legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. The Utility has been in settlement discussions with the district attorney's office since that time. On October 28, 2015, the district attorney informed the Utility that it would seek civil penalties in excess of $100,000 but is willing to continue to explore settlement options with the Utility.

For more information, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

## ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see the section of the 2015 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Cautionary Language Regarding Forward-Looking Statements."

***PG&E Corporation and the Utility may incur material liability in connection with the Butte fire*.**

On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the "Butte fire," the wildfire that ignited and spread in Amador and Calaveras Counties in Northern California in September 2015. Cal Fire's report co ncluded that the wildfire was caused when a Gray Pine tree contacted a n electric line of the Utility, which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

In connection with the Butte fire, approximately 3 2 complaints have been filed to date against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving approximately 1,300 individual plaintiffs and their insurance companies. The number of complaints may increase in the future. PG&E Corporation's and the Utility's financial statements for the period ended March 31, 2016 reflect a provision of $350 million for property damages in connection with this matter. This amount is based on estimates about the number, size, and type of structures damaged or destroyed, and assumptions about the contents of such structures and other property damage. A change in management's estimates or assumptions coul d result in an adjustment that c ould have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred. Th e Utility also could incur material charges related to fire suppression, personal injury damages and other damages.

The Utility has insurance coverage for third party clai ms. If the amount of insurance is insufficient to cover such losses , or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected.

The Utility also could be subject to material fines, or penalties or disallowances if the CPUC or other law enforcement agency brought enforcement action against the Utility.

## ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the quarter ended March 31, 2016 , PG&E Corporation made equity contributions totaling $ 65 million to the Utility in order to maintain the 52% common equity component of the Utility's CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended March 31, 2016 .

**Issuer Purchases of Equity Securities**

During the quarter ended March 31, 2016 , PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended March 31, 2016 , the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

## ITEM 5. OTHER INFORMATION

**Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends**

The Utility's earnings to fixed charges ratio for the three months ended March 31, 2016 was 0.75. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2016 was 0.74 . The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement No. 333-193879.

PG&E Corporation's earnings to fixed charges ratio for the three months ended March 31, 2016 was 0.75 . The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-193880.

## ITEM 6. EXHIBITS

| | |
|---|---|
| 3 | Bylaws of PG&E Corporation amended as of February 17, 2016 |
| 4 | Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on March 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 10.1 | Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on March 4, 2016 (File No. 1-2348), Exhibit 10.1) |
| *10. 2 | Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016 |
| *10. 3 | Separation agreement between Pacific Gas and Electric Company and Greg Kiraly dated February 18, 2016 |
| *10. 4 | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 16, 2016 |
| 12.1 | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 31.1 | Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Principal Executive Officer s and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| **32.1 | Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
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| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

*Management contract or compensatory agreement.
** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

/s/ JASON P. WELLS

Jason P. Wells
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

/s/ DINYAR B. MISTRY

Dinyar B. Mistry
Senior Vice President, Human Resources, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: May 4, 2016

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# Bylaws
# of
# PG&E Corporation
## <u>amended as of February 17, 2016</u>

## Article I.
## SHAREHOLDERS.

1. **Place of Meeting** . All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings** . The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given, by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation pursuant to this Section or Section 3. Other than director nominations pursuant to Section 3, to be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, other than director nominations pursuant to Section 3, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section and Section 3.

3. **Nominations of Directors Included in the Corporation's Proxy Materials.**

(a) **Inclusion of Shareholder Nominee in Proxy Statement** . Subject to the provisions of this Section 3, if expressly requested in the relevant Nomination Notice (as defined in Section 3(d) below), the Corporation shall include in its proxy statement for any annual meeting of shareholders (but not at any special meeting of shareholders): (i) the name of any person nominated for election (the "Shareholder Nominee"), which shall also be included on the Corporation's form of proxy and ballot, by any Eligible Shareholder (as defined in Section 3(c)(i) below) or group of up to 20 Eligible Shareholders that, as determined by the Board of Directors or its designee acting in good faith, has (individually and collectively, in the case of a group) satisfied all applicable conditions and complied with all applicable procedures set forth in this Section 3 (such Eligible Shareholder or group of Eligible Shareholders being a "Nominating Shareholder"); (ii) disclosure about the Shareholder Nominee and the Nominating Shareholder required under the rules of the Securities and Exchange Commission or other applicable law to be included in the proxy statement; (iii) any statement included by the Nominating Shareholder in the Nomination Notice for inclusion in the proxy statement in support of the Shareholder Nominee's election to the Board of Directors (subject, without limitation, to Section 3(e)(ii), provided that such statement does not exceed 500 words; and (iv) any other information that the Corporation or the Board of Directors determines, in their discretion, to include in the proxy statement relating to the nomination of the Shareholder Nominee, including, without limitation, any statement in opposition to the nomination and any of the information provided pursuant to this Section 3.

(b) **Maximum Number of Shareholder Nominees** .

(i) The Corporation shall not be required to include in the proxy statement for an annual meeting of shareholders more Shareholder Nominees than that number of directors constituting 20 percent of the total number of directors of the Corporation on the last day on which a Nomination Notice may be submitted pursuant to this Section 3 (rounded down to the nearest whole number), but, in any event, not fewer than two (the "Maximum Number"). The Maximum Number for a particular annual meeting shall be reduced by: (1) Shareholder Nominees whose nominations are subsequently withdrawn and (2) Shareholder Nominees whom the Board of Directors itself decides to nominate for election at such annual meeting. In the event that one or more vacancies for any reason occurs on the Board of Directors after the deadline set forth in Section 3(d) but before the date of the annual meeting of shareholders and the Board of Directors resolves to reduce the size of the Board in connection therewith, the Maximum Number shall be calculated based on the number of directors in office as so reduced.

(ii) If the number of Shareholder Nominees pursuant to this Section 3 for any annual meeting of shareholders exceeds the Maximum Number, then, promptly upon notice from the Corporation, each Nominating Shareholder will select one Shareholder Nominee for inclusion in the proxy statement until the Maximum Number is reached, going in order of the amount (largest to smallest) of shares of the Corporation's common stock that each Nominating Shareholder disclosed as owned in its Nomination Notice, with the process repeated if the Maximum Number is not reached after each Nominating Shareholder has selected one Shareholder Nominee. If, after the deadline for submitting a Nomination Notice as set forth in Section 2(d), a Nominating Shareholder becomes ineligible or withdraws its nomination, or a Shareholder Nominee becomes ineligible or unwilling to serve on the Board of Directors, whether before or after the mailing of the definitive proxy statement, then the Corporation: (1) shall not be required to include in its proxy statement or on any ballot or form of proxy the Shareholder Nominee or any successor or replacement nominee proposed by the Nominating Shareholder or by any other Nominating Shareholder and (2) may otherwise communicate to its shareholders, including without limitation by amending or supplementing its proxy statement or ballot or form of proxy, that the Shareholder Nominee will not be included as a Shareholder Nominee in the proxy statement or on any ballot or form of proxy and will not be voted on at the annual meeting of shareholders.

(c) **Eligibility of Nominating Shareholder** .

(i) An "Eligible Shareholder" is a person who has either (1) been a record holder of the shares of common stock of the Corporation used to satisfy the eligibility requirements in this Section 3(c) continuously for the three-year period specified in subsection (c)(ii) of this Section 3 below or (2) provides to the Corporate Secretary of the Corporation, within the time period referred to in Section 3(d), evidence of continuous ownership of such shares for such three-year period from one or more securities intermediaries in a form that the Board of Directors or its designee, acting in good faith, determines acceptable.

(ii) An Eligible Shareholder or group of up to 20 Eligible Shareholders may submit a nomination in accordance with this Section 3 only if the person or group (in the aggregate) has continuously owned at least the Minimum Number (as defined in Section 3(c)(iii) below) (as adjusted for any stock splits, reverse stock splits, stock dividends or similar events) of shares of the Corporation's common stock throughout the three-year period preceding and including the date of submission of the Nomination Notice, and continues to own at least the Minimum Number of shares through the date of the annual meeting of shareholders. The following shall be treated as one Eligible

Shareholder if such Eligible Shareholder shall provide together with the Nomination Notice documentation satisfactory to the Board of Directors or its designee, acting in good faith, that demonstrates compliance with the following criteria: (1) funds under common management and investment control; (2) funds under common management and funded primarily by the same employer; or (3) a "family of investment companies" or a "group of investment companies" (each as defined in the Investment Company Act of 1940, as amended). For the avoidance of doubt, in the event of a nomination by a Nominating Shareholder that includes more than one Eligible Shareholder, any and all requirements and obligations for a given Eligible Shareholder or, except as the context otherwise makes clear, the Nominating Shareholder that are set forth in this Section 3, including the minimum holding period, shall apply to each member of such group; provided, however, that the Minimum Number shall apply to the aggregate ownership of the group of Eligible Shareholders constituting the Nominating Shareholder. Should any Eligible Shareholder withdraw from a group of Eligible Shareholders constituting a Nominating Shareholder at any time prior to the annual meeting of shareholders, the Nominating Shareholder shall be deemed to own only the shares held by the remaining Eligible Shareholders. As used in this Section 3, any reference to a "group" or "group of Eligible Shareholders" refers to any Nominating Shareholder that consists of more than one Eligible Shareholder and to all the Eligible Shareholders that make up such Nominating Shareholder.

(iii) The "Minimum Number" of shares of the Corporation's common stock means 3 percent of the number of outstanding shares of common stock of the Corporation as of the most recent date for which such amount is given in any filing by the Corporation with the Securities and Exchange Commission prior to the submission of the Nomination Notice.

(iv) For purposes of this Section 3, an Eligible Shareholder "owns" only those outstanding shares of the Corporation's common stock as to which such Eligible Shareholder possesses both: (1) the full voting and investment rights pertaining to such shares and (2) the full economic interest in (including the opportunity for profit from and the risk of loss on) such shares; provided that the number of shares calculated in accordance with clauses (1) and (2) shall not include any shares (x) sold by such Eligible Shareholder or any of its affiliates in any transaction that has not been settled or closed, (y) borrowed by such Eligible Shareholder or any of its affiliates for any purpose or purchased by such Eligible Shareholder or any of its affiliates pursuant to an agreement to resell, or (z) subject to any option, warrant, forward contract, swap, contract of sale, or other derivative or similar agreement entered into by such Eligible Shareholder or any of its affiliates, whether any such instrument or agreement is to be settled with shares or with cash based on the notional amount or value of outstanding capital stock of the Corporation, in any such case which instrument or agreement has, or is intended to have, the purpose or effect of: (A) reducing in any manner, to any extent or at any time in the future, such Eligible Shareholder's or any of its affiliates' full right to vote or direct the voting of any such shares, and/or (B) hedging, offsetting, or altering to any degree any gain or loss arising from the full economic ownership of such shares by such Eligible Shareholder or any of its affiliates. An Eligible Shareholder "owns" shares held in the name of a nominee or other intermediary so long as the Eligible Shareholder retains the right to instruct how the shares are voted with respect to the election of directors and possesses the full economic interest in the shares. An Eligible Shareholder's ownership of shares shall be deemed to continue during any period in which the Eligible Shareholder has delegated any voting power by means of a proxy, power of attorney, or other similar instrument or arrangement that is revocable at any time by the Eligible Shareholder. An Eligible Shareholder's ownership of shares shall be deemed to continue during any period in which the Eligible Shareholder has loaned such shares, provided that the Eligible Shareholder has the power to recall such loaned shares on not more than five business days' notice. The terms "owned," "owning," and other variations of the word "own" shall have correlative meanings. Whether outstanding shares of the Corporation are "owned" for these purposes shall be determined by the Board of Directors or its designee acting in good faith. For purposes of this Section 3(c)(iv), the term "affiliate" or "affiliates" shall have the meaning ascribed thereto under the General Rules and Regulations under the Securities Exchange Act of 1934, as amended ("Exchange Act").

(v) No Eligible Shareholder shall be permitted to be in more than one group constituting a Nominating Shareholder, and if any Eligible Shareholder appears as a member of more than one group, such Eligible Shareholder shall be deemed to be a member of only the group that has the largest ownership position as reflected in the Nomination Notice.

(d) **Nomination Notice** . To nominate a Shareholder Nominee pursuant to this Section 3, the Nominating Shareholder must submit to the Corporate Secretary of the Corporation all of the following information and documents in a form that the Board of Directors or its designee, acting in good faith, determines acceptable (collectively, the "Nomination Notice"), not less than 120 days nor more than 150 days prior to the anniversary of the date that the Corporation mailed its proxy statement for the prior year's annual meeting of shareholders; provided, however, that if (and only if) the annual meeting of shareholders is not scheduled to be held within a period that commences 30 days

before the first anniversary date of the preceding year's annual meeting of shareholders and ends 30 days after the first anniversary date of the preceding year's annual meeting of shareholders (an annual meeting date outside such period being referred to herein as an "Other Meeting Date"), the Nomination Notice shall be given in the manner provided herein by the later of the close of business on the date that is 180 days prior to such Other Meeting Date or the tenth day following the date such Other Meeting Date is first publicly announced or disclosed (in no event shall the adjournment or postponement of an annual meeting, or the announcement thereof, commence a new time period (or extend any time period) for the giving of the Nomination Notice):

(i) one or more written statements from the record holder of the shares (and from each intermediary through which the shares are or have been held during the requisite three-year holding period) verifying that, as of a date within seven (7) calendar days prior to the date of the Nomination Notice, the Nominating Shareholder owns, and has continuously owned for the preceding three (3) years, the Minimum Number of shares, and the Nominating Shareholder's agreement to provide, within five (5) business days after the record date for the annual meeting, written statements from the record holder and intermediaries verifying the Nominating Shareholder's continuous ownership of the Minimum Number of shares through the record date;

(ii) an agreement to provide immediate notice if the Nominating Shareholder ceases to own the Minimum Number of shares at any time prior to the date of the annual meeting;

(iii) a copy of the Schedule 14N (or any successor form) relating to the Shareholder Nominee, completed and filed with the Securities and Exchange Commission by the Nominating Shareholder as applicable, in accordance with Securities and Exchange Commission rules;

(iv) the written consent of each Shareholder Nominee to being named in the Corporation's proxy statement, form of proxy, and ballot as a nominee and to serving as a director if elected;

(v) a written notice of the nomination of such Shareholder Nominee that includes the following additional information, agreements, representations, and warranties by the Nominating Shareholder (including, for the avoidance of doubt, each group member in the case of a Nominating Shareholder consisting of a group of Eligible Shareholders): (1) the information that would be required to be set forth in a shareholder's notice of nomination pursuant to Article I, Section 2 of these Bylaws; (2) the details of any relationship that existed within the past three years and that would have been described pursuant to Item 6(e) of Schedule 14N (or any successor item) if it existed on the date of submission of the Schedule 14N; (3) a representation and warranty that the Nominating Shareholder did not acquire, and is not holding, securities of the Corporation for the purpose or with the effect of influencing or changing control of the Corporation; (4) a representation and warranty that the Nominating Shareholder has not nominated and will not nominate for election to the Board of Directors at the annual meeting any person other than such Nominating Shareholder's Shareholder Nominee(s); (5) a representation and warranty that the Nominating Shareholder has not engaged in and will not engage in a "solicitation" within the meaning of Rule 14a-1(l) under the Exchange Act (without reference to the exception in Section 14a-(l)(2)(iv)) with respect to the annual meeting, other than with respect to such Nominating Shareholder's Shareholder Nominee(s) or any nominee of the Board of Directors); (6) a representation and warranty that the Nominating Shareholder will not use any proxy card other than the Corporation's proxy card in soliciting shareholders in connection with the election of a Shareholder Nominee at the annual meeting; (7) a representation and warranty that the Shareholder Nominee's candidacy or, if elected, Board membership would not violate applicable state or federal law or the rules of any stock exchange on which the Corporation's securities are traded (the "Stock Exchange Rules"); (8) a representation and warranty that the Shareholder Nominee: (A) does not have any direct or indirect relationship with the Corporation that will cause the Shareholder Nominee to be deemed not independent pursuant to the Corporation's Corporate Governance Guidelines and director independence standards and otherwise qualifies as independent under the Corporation's Corporate Governance Guidelines, director independence standards, and the Stock Exchange Rules; (B) meets the audit committee and compensation committee independence requirements under the Stock Exchange Rules; (C) is a "non-employee director" for the purposes of Rule 16b-3 under the Exchange Act (or any successor rule); (D) is an "outside director" for the purposes of Section 162(m) of the Internal Revenue Code (or any successor provision); (E) is not and has not been subject to any event specified in Rule 506(d)(1) of Regulation D (or any successor rule) under the Securities Act of 1933 or Item 401(f) of Regulation S-K (or any successor rule) under the Exchange Act, without reference to whether the event is material to an evaluation of the ability or integrity of the Shareholder Nominee; and (F) meets the director qualifications set forth in the Corporation's Corporate Governance Guidelines; (9) a representation and warranty that the Nominating Shareholder satisfies the eligibility requirements set forth in Section 3(c); (10) a representation and warranty that the Nominating Shareholder will continue to satisfy the eligibility requirements described in Section 3(c) through the date of the annual meeting; (11) details of any position of the Shareholder Nominee as an officer or director of any competitor (that is, any entity that produces products or provides services that compete with or are alternatives to the principal products produced or services provided by the Corporation

or its affiliates) of the Corporation, within the three years preceding the submission of the Nomination Notice; (12) if desired, a statement for inclusion in the proxy statement in support of the Shareholder Nominee's election to the Board of Directors, provided that such statement shall not exceed 500 words and shall fully comply with Section 14 of the Exchange Act and the rules and regulations thereunder; and (13) in the case of a nomination by a Nominating Shareholder comprised of a group, the designation by all Eligible Shareholders in such group of one Eligible Shareholder that is authorized to act on behalf of the Nominating Shareholder with respect to matters relating to the nomination, including withdrawal of the nomination;

(vi) an executed agreement pursuant to which the Nominating Shareholder (including in the case of a group, each Eligible Shareholder in that group) agrees: (1) to comply with all applicable laws, rules, and regulations in connection with the nomination, solicitation, and election; (2) to file any written solicitation or other communication with the Corporation's shareholders relating to one or more of the Corporation's directors or director nominees or any Shareholder Nominee with the Securities and Exchange Commission, regardless of whether any such filing is required under any rule or regulation or whether any exemption from filing is available for such materials under any rule or regulation; (3) to assume all liability stemming from an action, suit, or proceeding concerning any actual or alleged legal or regulatory violation arising out of any communication by the Nominating Shareholder or the Shareholder Nominee nominated by such Nominating Shareholder with the Corporation, its shareholders, or any other person in connection with the nomination or election of directors, including, without limitation, the Nomination Notice; (4) to indemnify and hold harmless (jointly and severally with all other Eligible Shareholders, in the case of a group of Eligible Shareholders) the Corporation and each of its directors, officers, and employees individually against any liability, loss, damages, expenses, or other costs (including attorneys' fees) incurred in connection with any threatened or pending action, suit, or proceeding, whether legal, administrative, or investigative, against the Corporation or any of its directors, officers, or employees arising out of or relating to a failure or alleged failure of the Nominating Shareholder or Shareholder Nominee to comply with, or any breach or alleged breach of, its, or his or her, as applicable, obligations, agreements, or representations under this Section 3; (5) in the event that any information included in the Nomination Notice, or any other communication by the Nominating Shareholder (including with respect to any Eligible Shareholder included in a group) with the Corporation, its shareholders, or any other person in connection with the nomination or election ceases to be true and accurate in all material respects (or due to a subsequent development omits a material fact necessary to make the statements made not misleading), to promptly (and in any event within 48 hours of discovering such misstatement or omission) notify the Corporation and any other recipient of such communication of the misstatement or omission in such previously provided information and of the information that is required to correct the misstatement or omission; and (6) in the event that the Nominating Shareholder (including any Eligible Shareholder included in a group) has failed to continue to satisfy the eligibility requirements described in Section 3(c), to promptly notify the Corporation; and

(vii) an executed agreement by the Shareholder Nominee: (1) to provide to the Corporation such other information, including completion of the Corporation's director nominee questionnaire, as the Board of Directors or its designee, acting in good faith, may request; (2) that the Shareholder Nominee has read and agrees, if elected to serve as a member of the Board of Directors, to adhere to the Corporation's Corporate Governance Guidelines, Code of Business Conduct and Ethics for Directors, and any other Corporation policies and guidelines applicable to directors; and (3) that the Shareholder Nominee is not and will not become a party to (A) any compensatory, payment or other financial agreement, arrangement, or understanding with any person or entity in connection with such person's nomination, candidacy, service, or action as director of the Corporation that has not been fully disclosed to the Corporation prior to or concurrently with the Nominating Shareholder's submission of the Nomination Notice, (B) any agreement, arrangement, or understanding with any person or entity as to how the Shareholder Nominee would vote or act on any issue or question as a director (a "Voting Commitment") that has not been fully disclosed to the Corporation prior to or concurrently with the Nominating Shareholder's submission of the Nomination Notice, or (C) any Voting Commitment that could limit or interfere with the Shareholder Nominee's ability to comply, if elected as a director of the Corporation, with his or her fiduciary duties under applicable law.

The information and documents required by this Section 3(d) shall be (i) provided with respect to and executed by each Eligible Shareholder in the group in the case of a Nominating Shareholder comprised of a group of Eligible Shareholders; and (ii) provided with respect to the persons specified in Instructions 1 and 2 to Items 6(c) and (d) of Schedule 14N (or any successor item) (x) in the case of a Nominating Shareholder that is an entity and (y) in the case of a Nominating Shareholder that is a group that includes one or more Eligible Shareholders that are entities. The Nomination Notice shall be deemed submitted on the date on which all of the information and documents referred to in this Section 3(d) (other than such information and documents contemplated to be provided after the date the Nomination Notice is provided) have been delivered to or, if sent by mail, received by the Corporate Secretary of the Corporation.

(e) **Exceptions** .

(i) Notwithstanding anything to the contrary contained in this Section 3, the Corporation may omit from its proxy statement any Shareholder Nominee and any information concerning such Shareholder Nominee (including a Nominating Shareholder's statement in support) and no vote on such Shareholder Nominee will occur (notwithstanding that proxies in respect of such vote may have been received by the Corporation), and the Nominating Shareholder may not, after the last day on which a Nomination Notice would be timely, cure in any way any defect preventing the nomination of the Shareholder Nominee, if: (1) the Corporation receives a notice that a shareholder intends to nominate a candidate for director at the annual meeting pursuant to the advance notice requirements set forth in Article I, Section 2 of these Bylaws; (2) the Nominating Shareholder (or, in the case of a Nominating Shareholder consisting of a group of Eligible Shareholders, the Eligible Shareholder that is authorized to act on behalf of the Nominating Shareholder), or any qualified representative thereof, does not appear at the annual meeting to present the nomination submitted pursuant to this Section 3 or the Nominating Shareholder withdraws its nomination; (3) the Board of Directors or its designee, acting in good faith, determines that such Shareholder Nominee's nomination or election to the Board of Directors would result in the Corporation violating or failing to be in compliance with these Bylaws or the Corporation's Articles of Incorporation or any applicable law, rule, or regulation to which the Corporation is subject, including the Stock Exchange Rules; (4) the Shareholder Nominee has been, within the past three years, an officer or director of a competitor, as defined for purposes of Section 8 of the Clayton Antitrust Act of 1914, as amended; or (5) the Corporation is notified, or the Board of Directors or its designee acting in good faith determines, that a Nominating Shareholder has failed to continue to satisfy the eligibility requirements described in Section 3(c), any of the representations and warranties made in the Nomination Notice ceases to be true and accurate in all material respects (or omits a material fact necessary to make the statement made not misleading), the Shareholder Nominee becomes unwilling or unable to serve on the Board of Directors, or any material violation or breach occurs of any of the obligations, agreements, representations, or warranties of the Nominating Shareholder or the Shareholder Nominee under this Section 3.

(ii) Notwithstanding anything to the contrary contained in this Section 3, the Corporation may omit from its proxy statement, or may supplement or correct, any information, including all or any portion of the statement in support of the Shareholder Nominee included in the Nomination Notice, if the Board of Directors or its designee in good faith determines that: (1) such information is not true in all material respects or omits a material statement necessary to make the statements made not misleading; (2) such information directly or indirectly impugns the character, integrity, or personal reputation of, or directly or indirectly makes charges concerning improper, illegal, or immoral conduct or associations, without factual foundation, with respect to, any individual, corporation, partnership, association, or other entity, organization, or governmental authority; (3) the inclusion of such information in the proxy statement would otherwise violate the Securities and Exchange Commission proxy rules or any other applicable law, rule, or regulation; or (4) the inclusion of such information in the proxy statement would impose a material risk of liability upon the Corporation.

The Corporation may solicit against, and include in the proxy statement its own statement relating to, any Shareholder Nominee.

4. **Special Meetings** . Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, the President, or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

5. **Voting at Meetings** . At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

6. **Shareholder Action by Written Consent.** Subject to Section 603 of the California Corporations Code,

any action which, under any provision of the California Corporations Code, may be taken at any annual or special meeting of shareholders may be taken without a meeting and without prior notice if a consent in writing, setting forth the action so taken, shall be signed by the holders of outstanding shares having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Any party seeking to solicit written consent from shareholders to take corporate action must deliver a notice to the Corporate Secretary of the Corporation which requests the Board of Directors to set a record date for determining shareholders entitled to give such consent. Such written request must set forth as to each matter the party proposes for shareholder action by written consents (a) a brief description of the matter and (b) the class and number of shares of the Corporation that are beneficially owned by the requesting party. Within ten days of receiving the request in the proper form, the Board shall set a record date for the taking of such action by written consent in accordance with California Corporations Code Section 701 and Article IV, Section 1 of these Bylaws. If the Board fails to set a record date within such ten-day period, the record date for determining shareholders entitled to give the written consent for the matters specified in the notice shall be the day on which the first written consent is given in accordance with California Corporations Code Section 701.

Each written consent delivered to the Corporation must set forth (a) the action sought to be taken, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, (d) the name and address of the proxyholder authorized by the shareholder to give such written consent, if applicable, and (d) any material interest of the shareholder or proxyholder in the action sought to be taken.

Consents to corporate action shall be valid for a maximum of sixty days after the date of the earliest dated consent delivered to the Corporation. Consents may be revoked by written notice (i) to the Corporation, (ii) to the shareholder or shareholders soliciting consents or soliciting revocations in opposition to action by consent proposed by the Corporation (the "Soliciting Shareholders"), or (iii) to a proxy solicitor or other agent designated by the Corporation or the Soliciting Shareholders.

Within three business days after receipt of the earliest dated consent solicited by the Soliciting Shareholders and delivered to the Corporation in the manner provided in California Corporations Code Section 603 or the determination by the Board of Directors of the Corporation that the Corporation should seek corporate action by written consent, as the case may be, the Corporate Secretary shall engage nationally recognized independent inspectors of elections for the purpose of performing a ministerial review of the validity of the consents and revocations. The cost of retaining inspectors of election shall be borne by the Corporation.

Consents and revocations shall be delivered to the inspectors upon receipt by the Corporation, the Soliciting Shareholders or their proxy solicitors, or other designated agents. As soon as consents and revocations are received, the inspectors shall review the consents and revocations and shall maintain a count of the number of valid and unrevoked consents. The inspectors shall keep such count confidential and shall not reveal the count to the Corporation, the Soliciting Shareholder or their representatives, or any other entity. As soon as practicable after the earlier of (i) sixty days after the date of the earliest dated consent delivered to the Corporation in the manner provided in California Corporations Code Section 603, or (ii) a written request therefor by the Corporation or the Soliciting Shareholders (whichever is soliciting consents), notice of which request shall be given to the party opposing the solicitation of consents, if any, which request shall state that the Corporation or Soliciting Shareholders, as the case may be, have a good faith belief that the requisite number of valid and unrevoked consents to authorize or take the action specified in the consents has been received in accordance with these Bylaws, the inspectors shall issue a preliminary report to the Corporation and the Soliciting Shareholders stating: (a) the number of valid consents, (b) the number of valid revocations, (c) the number of valid and unrevoked consents, (d) the number of invalid consents, (e) the number of invalid revocations, and (f) whether, based on their preliminary count, the requisite number of valid and unrevoked consents has been obtained to authorize or take the action specified in the consents.

Unless the Corporation and the Soliciting Shareholders shall agree to a shorter or longer period, the Corporation and the Soliciting Shareholders shall have forty-eight hours to review the consents and revocations and to advise the inspectors and the opposing party in writing as to whether they intend to challenge the preliminary report of the inspectors. If no written notice of an intention to challenge the preliminary report is received within forty-eight hours after the inspectors' issuance of the preliminary report, the inspectors shall issue to the Corporation and the Soliciting Shareholders their final report containing the information from the inspectors' determination with respect to whether the requisite number of valid and unrevoked consents was obtained to authorize and take the action specified in the consents. If the Corporation or the Soliciting Shareholders issue written notice of an intention to challenge the

inspectors' preliminary report within forty-eight hours after the issuance of that report, a challenge session shall be scheduled by the inspectors as promptly as practicable. A transcript of the challenge session shall be recorded by a certified court reporter. Following completion of the challenge session, the inspectors shall as promptly as practicable issue their final report to the Soliciting Shareholders and the Corporation, which report shall contain the information included in the preliminary report, plus all changes in the vote totals as a result of the challenge and a certification of whether the requisite number of valid and unrevoked consents was obtained to authorize or take the action specified in the consents. A copy of the final report of the inspectors shall be included in the book in which the proceedings of meetings of shareholders are recorded.

Unless the consent of all shareholders entitled to vote have been solicited in writing, the Corporation shall give prompt notice to the shareholders in accordance with California Corporations Code Section 603 of the results of any consent solicitation or the taking of the corporate action without a meeting and by less than unanimous written consent.

## Article II.
## DIRECTORS.

1. **Number** . As stated in paragraph I of Article Third of this Corporation's Articles of Incorporation, the Board of Directors of this Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13). The exact number of directors shall be twelve (12) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers** . The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees** . The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings** . Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, the Chief Executive Officer, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings** . The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum** . A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent** . Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone** . Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

9. **Majority Voting** . In any uncontested election, nominees receiving the affirmative vote of a majority of the shares represented and voting at a duly held meeting at which a quorum is present (which shares voting affirmatively also constitute at least a majority of the required quorum) shall be elected. In any election that is not an uncontested election, the nominees receiving the highest number of affirmative votes of the shares entitled to be voted for them, up to the number of directors to be elected by those shares, shall be elected; votes against a director and votes withheld shall have no legal effect.

For purposes of these Bylaws, "uncontested election" means an election of directors of the Corporation in which, at the expiration of the times fixed under Article I, Section 2 and Section 3 of these Bylaws requiring advance notification of director nominees, or for special meetings, at the time notice is given of the meeting at which the election is to occur, the number of nominees for election does not exceed the number of directors to be elected by the shareholders at that election.

If an incumbent director fails, in an uncontested election, to receive the vote required to be elected in accordance with this Article II, Section 9, then, unless the incumbent director has earlier resigned, the term of such incumbent director shall end on the date that is the earlier of (a) ninety (90) days after the date on which the voting results are determined pursuant to Section 707 of the California Corporations Code, or (b) the date on which the Board of Directors selects a person to fill the office held by that director in accordance with the procedures set forth in these Bylaws and Section 305 of the California Corporations Code.

## Article III.
## OFFICERS.

1. **Officers** . The officers of the Corporation shall be elected by the Board of Directors and include a President, a Corporate Secretary, a Treasurer, or other such officers as required by law. The Board of Directors also may elect one or more Vice Presidents, Assistant Secretaries, Assistant Treasurers, and other such officers as may be appropriate, including the offices described below. Any number of offices may be held by the same person.

2. **Chairman of the Board** . The Chairman of the Board shall be a member of the Board of Directors and preside at all meetings of the shareholders, of the Directors, and of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and, in the absence or disability of the Chief Executive Officer, shall exercise the Chief Executive Officer's duties and responsibilities.

3. **Vice Chairman of the Board** . The Vice Chairman of the Board shall be a member of the Board of Directors and have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee** . The Chairman of the Executive Committee shall be a member of the Board of Directors and preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **Chief Executive Officer.** The Chief Executive Officer shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. If there be no Chairman of the Board, the Chief Executive Officer shall also exercise the duties and responsibilities of that office. The Chief Executive Officer shall have authority to sign on behalf of the Corporation agreements and instruments of every character. In the absence or disability of the President, the Chief Executive Officer shall exercise the President's duties and responsibilities.

6. **President** . The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Chief Executive Officer, or the Bylaws. If there be no Chief Executive Officer, the President shall also exercise the duties and responsibilities of that office. The President shall have authority

to sign on behalf of the Corporation agreements and instruments of every character.

7. **Chief Financial Officer**. The Chief Financial Officer shall be responsible for the overall management of the financial affairs of the Corporation. The Chief Financial Officer shall render a statement of the Corporation's financial condition and an account of all transactions whenever requested by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, or the President.

The Chief Financial Officer shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

8. **General Counsel**. The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

9. **Vice Presidents**. Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, or the President may confer a special title upon any Vice President.

10. **Corporate Secretary**. The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

11. **Treasurer**. The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositaries as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, or the Bylaws.

The Assistant Treasurers shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

12. **Controller**. The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for

all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

## Article IV.
## MISCELLANEOUS.

1. **Record Date** . The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Certificates; Direct Registration System** . Shares of the Corporation's capital stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation's capital stock may also be evidenced by registration in the holder's name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the New York Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates** . Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate (or uncertificated shares in lieu of a new certificate) may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

## Article V.
## AMENDMENTS.

1. **Amendment by Shareholders** . Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.

2. **Amendment by Directors** . To the extent provided by law, these Bylaws, or any of them, may be

amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors; provided, however, that amendments to Article II, Section 9 of these Bylaws, and any other Bylaw provision that implements a majority voting standard for director elections (excepting any amendments intended to conform those Bylaw provisions to changes in applicable laws) shall be amended by the shareholders of the Corporation as provided in Section 1 of this Article V.

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**NON-ANNUAL RESTRICTED STOCK UNIT AWARD**

**PG&E CORPORATION** , a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2014 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: February 23, 2016

Name of Recipient: Dinyar Mistry

Recipient's Participant ID: XXXXXXXX

Number of Restricted Stock Units: 8,739

***By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this award, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock Units dated March 2, 2015.***

***If, for any reason, you wish to not accept this award, please notify PG&E Corporation in writing within 30 calendar days of the date of this award at ATTN: LTIP Administrator at Pacific Gas and Electric Company, 245 Market Street, N2T, San Francisco, 94105.***

Attachment

**PG&E CORPORATION**
**2014 LONG-TERM INCENTIVE PLAN**

**RESTRICTED STOCK UNIT AGREEMENT**

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| **The LTIP and Other Agreements** | This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP will govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy or the PG&E Corporation 2012 Officer Severance Policy, this Agreement will govern. For purposes of this Agreement, employment with PG&E Corporation means employment with any member of the Participating Company Group. |
| **Grant of Restricted Stock Units** | PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP. |
| **Vesting of Restricted Stock Units** | As long as you remain employed with PG&E Corporation, the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest in accordance with the below vesting schedule (the "Normal Vesting Schedule").<br>4,369 on February 23, 2018<br>4,370 on February 23, 2019<br>The amounts payable upon each vesting date are hereby designated separate payments for purposes of Code Section 409A. Except as described below, all Restricted Stock Units subject to this Agreement which have not vested upon termination of your employment will then be cancelled. As set forth below, the Restricted Stock Units may vest earlier upon the occurrence of certain events. |
| **Dividends** | Restricted Stock Units will accrue Dividend Equivalents in the event cash dividends are paid with respect to PG&E Corporation common stock having a record date prior to the date on which the Restricted Stock Units are settled. Such Dividend Equivalents will be converted into cash and paid, if at all, upon settlement of the underlying Restricted Stock Units. |
| **Settlement** | Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock, subject to the satisfaction of Withholding Taxes, as described below. PG&E Corporation will issue shares as soon as practicable after the Restricted Stock Units vest in accordance with the Normal Vesting Schedule (but not later than sixty (60) days after the applicable vesting date); provided, however, that such issuance will, if earlier, be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than sixty (60) days after) the earliest to occur of your (1) Disability (as defined under Code Section 409A), (2) death or (3) "separation from service," within the meaning of Code Section 409A within 2 years following a Change in Control. |
| **Voluntary Termination** | In the event of your voluntary termination, all unvested Restricted Stock Units will be cancelled on the date of termination. |
| **Termination for Cause** | If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause, all unvested Restricted Stock Units will be cancelled on the date of termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation. |
| **Termination other than for Cause** | If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause, any unvested Restricted Stock Units that would have vested within the 12 months following such termination had your employment continued will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. All other unvested Restricted Stock Units will be cancelled unless your termination of employment was in connection with a Change in Control as provided below. |
| **Death/Disability** | In the event of your death or Disability while you are employed, all of your Restricted Stock Units will vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. If your death or Disability occurs following the termination of your employment and your Restricted Stock Units are then outstanding under the terms hereof, then all of your vested Restricted Stock Units plus any Restricted Stock Units that would have otherwise vested during any continued vesting period hereunder will be settled as soon as practicable after (but not later than sixty (60) days after) the date of your death or Disability. |
| **Termination Due to Disposition of Subsidiary** | If your employment is terminated (other than termination for cause, your voluntary termination) (1) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the "Code"), or (2) coincident with |

the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, then your Restricted Stock Units will vest and be settled in the same manner as for a "Termination other than for Cause" described above.

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| **Change in Control** | In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without your consent, either assume or continue PG&E Corporation's rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement.<br>If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your unvested Restricted Stock Units will vest immediately preceding and contingent on, the Change in Control and be settled in accordance with the Normal Vesting Schedule, subject to the earlier settlement provisions of this Agreement. |
| **Termination In Connection with a Change in Control** | If you separate from service (other than termination for cause, your voluntary termination) in connection with a Change in Control within three months before the Change in Control occurs, all of your outstanding Restricted Stock Units (including Restricted Stock Units that you would have otherwise forfeited after the end of the continued vesting period) will vest on the date of the Change in Control and will be settled in accordance with the Normal Vesting Schedule (without regard to the requirement that you be employed) subject to the earlier settlement provisions of this Agreement.<br>In the event of such a separation in connection with a Change in Control within two years following the Change in Control, your Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this award) will vest on the date of such separation and will be settled as soon as practicable after (but not later than sixty (60) days after) the date of such separation. PG&E Corporation has the sole discretion to determine whether termination of your employment was made in connection with a Change in Control. |
| **Delay** | PG&E Corporation will delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain "key employees" of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your "separation from service" under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period. |
| **Withholding Taxes** | The number of shares of PG&E Corporation common stock that you are otherwise entitled to receive upon settlement of Restricted Stock Units will be reduced by a number of shares having an aggregate Fair Market Value, as determined by PG&E Corporation, equal to the amount of any Federal, state, or local taxes of any kind required by law to be withheld by PG&E Corporation in connection with the Restricted Stock Units determined using the applicable minimum statutory withholding rates, including social security and Medicare taxes due under the Federal Insurance Contributions Act and the California State Disability Insurance tax ("Withholding Taxes"). If the withheld shares were not sufficient to satisfy your minimum Withholding Taxes, you will be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Withholding Taxes that is not satisfied by the withholding of shares described above. |
| **Leaves of Absence** | For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."<br>Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you will be deemed to have had a "separation from service" for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence will be twenty-nine (29) months.<br>PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement. |
| **Voting and Other Rights** | You will not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent). |
| **No Retention Rights** | This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason. |

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| **Applicable Law** | This Agreement will be interpreted and enforced under the laws of the State of California. |

# SEPARATION AGREEMENT

This Separation Agreement ("Agreement") is made and entered into by and between Greg Kiraly and Pacific Gas And Electric Company ("PG&E" or "Company") (collectively the "Parties") and sets forth the terms and conditions of Mr. Kiraly's separation from employment with PG&E. The "Effective Date" of this Agreement is defined in paragraph 18a.

1. **Resignation.** Effective the close of business on March 4, 2016 Mr. Kiraly will resign from his position as Senior Vice President, Electric Transmission and Distribution. Mr. Kiraly shall have until February 26, 2016 to accept this Agreement by submitting a signed copy to PG&E. Regardless of whether Mr. Kiraly accepts this Agreement, on March 4, 2016 he will be paid all salary or wages and paid time off accrued, unpaid and owed to him as of that date, he will remain entitled to any other benefits to which he is otherwise entitled under the provisions of PG&E's plans and programs, and he will receive notice of the right to continue his existing health-insurance coverage pursuant to COBRA.

The benefits set forth in paragraph 2 below are conditioned upon Mr. Kiraly's acceptance of this Agreement.

2. **Separation benefits.** Even though Mr. Kiraly is not otherwise entitled to them, in consideration of his acceptance of this Agreement, PG&E will provide to Mr. Kiraly the following separation benefits:

   a. **Severance payment.** Under the terms of the 2012 PG&E Corporation Officer Severance Policy, Mr. Kiraly's severance payment amount is $586,830 (Five Hundred Eighty- Six Thousand Eight Hundred Thirty Dollars.) After the Effective Date of this Agreement as set forth in paragraph 18.a below and the execution of Exhibit A on March 4, 2016 PG&E will make the severance payment, less applicable withholdings and deductions, to Mr. Kiraly within seven business days.

   b. **Bonus.** Mr. Kiraly shall be entitled to receive a pro-rated bonus under PG&E's 2015 short-term incentive plan at the time such bonus, if any, would otherwise be paid.

   c. **Stock.** Upon his final day as a PG&E employee (March 4, 2016), but conditioned on the occurrence of the Effective Date of this Agreement as set forth in paragraph 18.a below, all unvested restricted stock grants and performance share grants provided to Mr. Kiraly under PG&E Corporation's 2006 Long-Term Incentive Plan and 2014 Long-Term Incentive Plan shall continue to vest, terminate, or be cancelled in accordance with the plans applicable to those awards.

   d. **Career transition services.** For a maximum period of one year following the Effective Date of this Agreement, PG&E will provide Mr. Kiraly with executive career transition services from Lee Hecht Harrison , with total payments to the firm not to exceed $12,000 (Twelve Thousand Dollars.). Lee Hecht Harrison shall bill PG&E directly for their services to Mr. Kiraly. Mr. Kiraly's entitlement to services under this Agreement will terminate when he becomes employed, either by another employer or through self-employment other than consulting with PG&E.

   e. **Payment of COBRA premium.** In addition to the severance payment described in paragraph 2.a, PG&E will pay Mr. Kiraly the amount of $42,451. (Forty Two Thousand Four Hundred Fifty- One Dollars), which is an estimated value of his monthly COBRA premiums for the eighteen-month period commencing the first full month after March 4, 2016.

3. **Defense and indemnification in third-party claims.** PG&E and/or its affiliate or subsidiary will provide Mr. Kiraly with legal representation and indemnification protection in any legal proceeding in which he is a party or is threatened to be made a party by reason of the fact that he is or was an employee or officer of PG&E and/or its affiliate or subsidiary, in accordance with the terms of the resolution of the Board of Directors of PG&E Corporation dated December 18 1996, any subsequent PG&E policy or plan providing greater protection to Mr. Kiraly, or as otherwise required by law.

4. **Cooperation with legal proceedings.** Mr. Kiraly will, upon reasonable notice, furnish information and proper assistance to PG&E and/or its affiliate or subsidiary (including truthful testimony and document production) as may reasonably be required by them or any of them in connection with any legal, administrative or regulatory proceeding in which they or any of them is, or may become, a party, or in connection with any filing or similar obligation imposed by any taxing, administrative or

regulatory authority having jurisdiction, provided, however, that PG&E and/or its affiliate or subsidiary will pay all reasonable expenses incurred by Mr. Kiraly in complying with this paragraph.

5. **Release of claims and covenant not to sue.**

**a.** In consideration of the separation benefits and other benefits PG&E is providing under this Agreement, Mr. Kiraly, on behalf of himself and his representatives, agents, heirs and assigns, waives, releases, discharges and promises never to assert any and all claims, liabilities or obligations of every kind and nature, whether known or unknown, suspected or unsuspected that he ever had, now has or might have as of the Effective Date against PG&E or its, predecessors, affiliates, subsidiaries, shareholders, owners, directors, officers, employees, agents, attorneys, successors, or assigns. These released claims include, without limitation, any claims arising from or related to Mr. Kiraly's employment with PG&E, or any of its affiliates and subsidiaries, and the termination of that employment. These released claims also specifically include, but are not limited, any claims arising under any federal, state and local statutory or common law, such as (as amended and as applicable) Title VII of the Civil Rights Act, the Age Discrimination in Employment Act, the Americans With Disabilities Act, the Employee Retirement Income Security Act, the California Fair Employment and Housing Act, the California Labor Code, any other federal, state or local law governing the terms and conditions of employment or the termination of employment, and the law of contract and tort; and any claim for attorneys' fees.

**b.** Mr. Kiraly acknowledges that there may exist facts or claims in addition to or different from those which are now known or believed by him to exist. Nonetheless, this Agreement extends to all claims of every nature and kind whatsoever, whether known or unknown, suspected or unsuspected, past or present, and Mr. Kiraly specifically waives all rights under Section 1542 of the California Civil Code which provides that:

A GENERAL RELEASE DOES NOT EXTEND TO CLAIMS WHICH THE CREDITOR DOES NOT KNOW OR SUSPECT TO EXIST IN HIS OR HER FAVOR AT THE TIME OF EXECUTING THE RELEASE, WHICH IF KNOWN TO HIM OR HER MUST HAVE MATERIALLY AFFECTED HIS OR HER SETTLEMENT WITH THE DEBTOR.

**c.** With respect to the claims released in the preceding paragraphs, Mr. Kiraly will not initiate or maintain any legal or administrative action or proceeding of any kind against PG&E or its predecessors, affiliates, subsidiaries, shareholders, owners, directors, officers, employees, agents, attorneys, successors, or assigns, for the purpose of obtaining any personal relief, nor (except as otherwise required or permitted by law) assist or participate in any such proceedings, including any proceedings brought by any third parties.

**d.** Mr. Kiraly agrees to reconfirm the release and covenants set forth herein by executing and returning the attached Exhibit A within 5 days after March 4, 2016. The Company shall be under no obligation to pay any obligation to Mr. Kiraly accruing after March 4, 2016 absent his signature and return of Exhibit A to the Company, unless otherwise required by law. In the event Mr. Kiraly should die or become legally incapacitated prior to executing and returning the attached Exhibit A, a release similar to that set forth in Exhibit A executed by his estate or legal representative will be sufficient to obligate the Company to pay all remaining obligations or benefits.

6. **Re-employment.** Mr. Kiraly will not seek any future re-employment with PG&E, or any of its subsidiaries or affiliates. This paragraph will not, however, preclude Mr. Kiraly from accepting an offer of future employment from PG&E or any of its subsidiaries or affiliates.

7. **Non-disclosure.**

**a.** Mr. Kiraly will not disclose, publicize, or circulate to anyone in whole or in part, any information concerning the existence, terms, and/or conditions of this Agreement without the express written consent of PG&E's Chief Legal Officer, or as reasonably necessary to enforce the terms of this Agreement, unless otherwise required or permitted by law. Notwithstanding the preceding sentence, Mr. Kiraly may disclose the terms and conditions of this Agreement to his family members, and any attorneys or tax advisors, if any, to whom there is a *bona fide* need for disclosure in order for them to render professional services to him, provided that the person first agrees to keep the information confidential and not to make any disclosure of the terms and conditions of this Agreement unless otherwise required or permitted by law.

**b.** Mr. Kiraly will not use, disclose, publicize, or circulate any confidential or proprietary information concerning PG&E or its subsidiaries or affiliates, which has come to his attention during his employment with PG&E, unless doing so is expressly authorized in writing by PG&E's Chief Legal Officer, or is otherwise required or permitted by law. Before making any legally-required or permitted disclosure, Mr. Kiraly will give PG&E notice at least ten (10) business days in advance.

8. **Non-Disparagement.** Mr. Kiraly agrees to refrain from performing any act, engaging in any conduct or course of action or making or publishing any statements, claims, allegations or assertions, which have or may reasonably have the effect of demeaning the name or business reputation of PG&E, or any of its subsidiaries or affiliates, or any of their respective employees, officers, directors, agents or advisors in their capacities as such or which adversely affects (or may reasonably be expected adversely to affect) the best interests (economic or otherwise) of any of them. Nothing in this paragraph 8 shall preclude Mr. Kiraly from fulfilling any legal duty he may have, including responding to any subpoena or official inquiry from any court or government agency.

9. **No unfair competition.**

**a.** For a period of 18 months after the Effective Date, Mr. Kiraly will not engage in any unfair competition against PG&E or any of its subsidiaries or affiliates.

**b.** For a period of 18 months after the Effective Date, Mr. Kiraly will not, directly or indirectly, solicit or contact for the purpose of diverting or taking away or attempt to solicit or contact for the purpose of diverting or taking away:

(1) any existing customer of PG&E or its affiliates or subsidiaries;

(2) any prospective customer of PG&E or its affiliates or subsidiaries about whom Mr. Kiraly acquired information as a result of any solicitation efforts by PG&E or its affiliates or subsidiaries, or by the prospective customer, during Mr. Kiraly's employment with PG&E;

(3) any existing vendor of PG&E or its affiliates or subsidiaries;

(4) any prospective vendor of PG&E or its affiliates or subsidiaries, about whom Mr. Kiraly acquired information as a result of any solicitation efforts by PG&E or its affiliates or subsidiaries, or by the prospective vendor, during Mr. Kiraly's employment with PG&E;

(5) any existing employee, agent or consultant of PG&E or its affiliates or subsidiaries, to terminate or otherwise alter the person's or entity's employment, agency or consultant relationship with PG&E or its affiliates or subsidiaries; or

(6) any existing employee, agent or consultant of PG&E or its affiliates or subsidiaries, to work in any capacity for or on behalf of any person, company or other business enterprise that is in competition with PG&E or its affiliates or subsidiaries.

10. **Material breach by Employee.** In the event that Mr. Kiraly breaches any material provision of this Agreement, including but not necessarily limited to paragraphs 4, 5, 6, 7, 8, and/or 9, and fails to cure such breach upon reasonable notice, PG&E will be entitled to recover any actual damages and to recalculate any future pension benefit entitlement without the additional age he received or would have received under this Agreement. Despite any breach by Mr. Kiraly, his other duties and obligations under the Agreement, including his waivers and releases, will remain in full force and effect. In the event of a breach or threatened breach by Mr. Kiraly of any of the provisions in paragraphs 4, 5, 6, 7, 8, and/or 9, PG&E will, in addition to any other remedies provided in this Agreement, be entitled to equitable and/or injunctive relief and because the damages for such a breach or threatened breach will be difficult to determine and will not provide a full and adequate remedy, PG&E will also be entitled to specific performance by Mr. Kiraly of his obligations under paragraphs 4, 5, 6, 7, 8, and/or 9.

11. **Material breach by PG&E.** Mr. Kiraly will be entitled to recover actual damages in the event of any material breach of this Agreement by PG&E, including any unexcused late or non-payment of any amounts owed under this Agreement, or any unexcused failure to provide any other benefits specified in this Agreement. In the event of a breach or threatened breach by PG&E of any of its material obligations to him under this Agreement, Mr. Kiraly will be entitled to seek, in addition to any other remedies provided in this Agreement, specific performance of PG&E's obligations and any other applicable equitable or injunctive relief.

12. **No admission of liability.** This Agreement is not, and will not be considered, an admission of liability or of a violation of any applicable contract, law, rule, regulation, or order of any kind.

13. **Complete agreement.** This Agreement sets forth the entire agreement between the Parties pertaining to the subject matter of this Agreement and fully supersedes any prior or contemporaneous negotiations, representations, agreements, or understandings between the Parties with respect to any such matters, whether written or oral (including any that would have provided Mr. Kiraly with any different severance arrangements). The Parties acknowledge that they have not relied on any promise, representation or warranty, express or implied, not contained in this Agreement. Parole evidence will be inadmissible to show agreement by and among the Parties to any term or condition contrary to or in addition to the terms and conditions contained in this Agreement.

14. **Severability.** If any provision of this Agreement is determined to be invalid, void, or unenforceable, the remaining provisions will remain in full force and effect.

15. **Arbitration.** With the exception of any request for specific performance, injunctive or other equitable relief, any dispute or controversy of any kind arising out of or related to this Agreement, Mr. Kiraly's employment with PG&E, the separation of Mr. Kiraly from that employment and from his position as an officer and/or director of PG&E or any subsidiary or affiliate, or any claims for benefits, will be resolved exclusively by final and binding arbitration using a three-member arbitration panel in accordance with the Commercial Arbitration Rules of the American Arbitration Association currently in effect, provided, however, that in rendering their award, the arbitrators will be limited to those legal rights and remedies provided by law. The only claims not covered by this paragraph are any non-waivable claims for benefits under workers' compensation or unemployment insurance laws, which will be resolved under those laws. Any arbitration pursuant to this paragraph will take place in San Francisco, California. The Parties may be represented by legal counsel at the arbitration but must bear their own fees for such representation in the first instance. The prevailing party in any dispute or controversy covered by this paragraph, or with respect to any request for specific performance, injunctive or other equitable relief, will be entitled to recover, in addition to any other available remedies specified in this Agreement, all litigation expenses and costs, including any arbitrator, administrative or filing fees and reasonable attorneys' fees, except as prohibited or limited by law. The Parties specifically waive any right to a jury trial on any dispute or controversy covered by this paragraph. Judgment may be entered on the arbitrators' award in any court of competent jurisdiction. Subject to the arbitration provisions of this paragraph, the sole jurisdiction and venue for any action related to the subject matter of this Agreement will be the California state and federal courts having within their jurisdiction the location of PG&E's principal place of business in California at the time of such action, and both Parties thereby consent to the jurisdiction of such courts for any such action.

16. **Governing law.** This Agreement will be governed by and construed under the laws of the United States and, to the extent not preempted by such laws, by the laws of the State of California, without regard to their conflicts of laws provisions.

17. **No waiver.** The failure of either Party to exercise or enforce, at any time, or for any period of time, any of the provisions of this Agreement will not be construed as a waiver of that provision, or any portion of that provision, and will in no way affect that party's right to exercise or enforce such provisions. No waiver or default of any provision of this Agreement will be deemed to be a waiver of any succeeding breach of the same or any other provisions of this Agreement.

18. **Acceptance of Agreement.**

**a.** Mr. Kiraly was provided more than 21 days to consider and accept the terms of this Agreement and was advised to consult with an attorney about the Agreement before signing it. The provisions of the Agreement are, however, not subject to negotiation. After signing the Agreement, Mr. Kiraly will have an additional seven (7) days in which to revoke in writing acceptance of this Agreement. To revoke, Mr. Kiraly will submit a signed statement to that effect to PG&E's Chief Legal Officer before the close of business on the seventh day. If Mr. Kiraly does not submit a timely revocation, the Effective

Date of this Agreement will be the eighth day after he has signed it.

**b.** Mr. Kiraly acknowledges reading and understanding the contents of this Agreement, being afforded the opportunity to review carefully this Agreement with an attorney of his choice, not relying on any oral or written representation not contained in this Agreement, signing this Agreement knowingly and voluntarily, and, after the Effective Date of this Agreement, being bound by all of its provisions.

| | | |
|---|---|---|
| | | PACIFIC GAS AND ELECTRIC COMPANY |
| Dated: | 2/18/16 | By: JOHN R. SIMON |
| | | Title: EVP |
| | | GREG KIRALY |
| Dated: | 2/12/16 | GREG KIRALY |

EXHIBIT A

EMPLOYMENT TERMINATION CERTIFICATE

I entered into a **SEPARATION AGREEMENT (" *Separation Agreement* ")** with Pacific Gas And Electric Company ("PG&E") dated February 12, 2016. I hereby acknowledge that:

(1) A blank copy of this Employment Termination Certificate was attached as Exhibit A to the Separation Agreement when PG&E gave it to me for review. I have been given sufficient and reasonable time to consider signing this Certificate. I have been advised of my right to discuss the Separation Agreement and this Certificate with an attorney before executing either document.

(2) The benefits payable under paragraph 2(a)-(e) of the Separation Agreement are only payable to me if I sign this Certificate after the Date of Resignation as defined in the Separation Agreement as March 4, 2016.

(3) I executed the Separation Agreement prior to my last day of employment. In exchange for the remaining benefits provided for in paragraph 2(a)-(e) of the Separation Agreement, I hereby agree that this Certificate will be a part of my Separation Agreement such that the release of claims and the covenants that I provided under paragraph 5 of the Separation Agreement will, by my signature below, extend to and cover any other claims that arose after the Effective Date, up to and including the Date of Resignation and the date this Certificate is signed, provided, however, by signing the Employment Termination Certificate I am not releasing any claim I have to receive any and all benefits otherwise due to me under the terms of the Separation Agreement, or otherwise required by law.

(4) Nothing in this Certificate alters, diminishes, or mitigates the scope and breadth of the releases and covenants that I previously provided to PG&E under the Separation Agreement, which shall remain in full force and effect regardless of whether I sign this Certificate.

(5) By signing below, I hereby extend the release of claims and the covenants that I provided to PG&E and other released parties under the Separation Agreement to cover any other claims (as more fully described in paragraph 5 of the Separation Agreement) that arose or may have arisen at any time after the Effective Date, up to and including the Date of Resignation and the date this Certificate is signed. I knowingly and voluntarily waive any and all rights or benefits which I may have had, may now have or in the future may have under the terms of Section 1542 of the California Civil Code, which provides as follows:

> **A GENERAL RELEASE DOES NOT EXTEND TO CLAIMS WHICH THE CREDITOR DOES NOT KNOW OR SUSPECT TO EXIST IN HIS OR HER FAVOR AT THE TIME OF EXECUTING THE RELEASE WHICH, IF KNOWN BY HIM OR HER MUST HAVE MATERIALLY AFFECTED HIS OR HER SETTLEMENT WITH THE DEBTOR.**

I understand that section 1542 gives me the right not to release existing claims of which I am not now aware, but I expressly and voluntarily choose to waive my rights under California Civil Code Section 1542, as well as under any other federal or state statute or common law principles of similar effect .

I UNDERSTAND THAT I HAVE A RIGHT TO CONSULT WITH AN ATTORNEY OF MY OWN CHOOSING AND TO HAVE THE TERMS OF THIS CERTIFICATE FULLY EXPLAINED TO ME PRIOR TO SIGNING, AND THAT I AM GIVING UP ANY LEGAL CLAIMS I HAVE AGAINST THE PARTIES RELEASED IN THE SEPARATION AGREEMENT BY SIGNING THIS CERTIFICATE. I AM SIGNING THIS CERTIFICATE KNOWINGLY, WILLINGLY AND VOLUNTARILY IN EXCHANGE FOR THE BENEFITS DESCRIBED IN THE SEPARATION AGREEMENT.

GREG KIRALY

______________________________
Greg Kiraly

2/26/16
Date: __________________________

**EXHIBIT 10.4**

# AMENDMENT
# TO THE
# POSTRETIREMENT LIFE INSURANCE PLAN OF
# THE PACIFIC GAS AND ELECTRIC COMPANY

A. Adoption and effective date of amendment. This Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (the "Plan") is adopted by the Board of Directors of the Pacific Gas and Electric Company to restate and update the Plan's governance structure. This Amendment shall be effective as of February 16, 2016.

B. Supersession of inconsistent provisions. This Amendment shall supersede the provisions of the Plan to the extent those provisions are inconsistent with the provisions of this Amendment.

C. The Preamble to the Plan is restated to read as follows:

This is the controlling and definitive statement of the Pacific Gas and Electric Company Postretirement Life Insurance Plan ("PLAN"). The PLAN is for the benefit of all eligible employees of Pacific Gas and Electric Company ("COMPANY") and the EMPLOYERS. The PLAN was first adopted in substantially its current form by the BOARD OF DIRECTORS in 1978 and has since been amended from time to time. Except as expressly stated by any amendment to this PLAN, benefits of eligible employees who retire, terminate from employment, or cease to be an eligible employee prior to the effective date of any amendment shall not be affected by any such amendment.

D. Section 1.02 of the Plan is amended to read as follows:

1.02 Bargaining Unit Employee shall mean an employee of the COMPANY or of an EMPLOYER, and who is a member of a collective bargaining unit.

E. Section 1.03 of the Plan is amended to read as follows:

1.03 Beneficiary shall mean the individual or individuals or intervivos trust or trusts that an eligible employee designates to receive benefits under Section 3.02. Such designation must be made on a form provided by, and filed with, the PLAN ADMINISTRATOR.

F. A new Section 1.03A of the Plan is added to read as follows:

1.03A Benefits shall mean the Benefits Department of the COMPANY, 1850 Gateway Boulevard, 7th Floor, Concord, CA 94250.

G. A new Section 1.04A of the Plan is added to read as follows:

1.04A Claim Administrator shall mean an entity which regularly engages in the business of providing claims administration, adjustment and payment and claim review services to employee welfare benefit plans, including an insurer. The Claim Administrator for the PLAN is listed in the most recent SUMMARY PLAN DESCRIPTION as modified by subsequent SUMMARIES OF MATERIAL MODIFICATIONS.

H. A new Section 1.04B of the Plan is added to read as follows:

1.04B Code shall mean the Internal Revenue Code of 1986, as amended.

I. A new Section 1.06A of the Plan is added to read as follows:

1.06A Employee Benefit Appeals Committee shall mean the committee consisting of the senior officer for Human Resources of the COMPANY (or his or her delegate), the General Counsel of the COMPANY (or his or her delegate) and one other employee or officer of the COMPANY selected by the aforedesignated persons. If there is no senior officer for Human Resources of the COMPANY, then a senior vice president of PG&E Corporation (or, if such role is vacant, the equivalent position at the COMPANY) will instead be a member of the Employee Benefit Appeals Committee. Action of the Employee Benefit Appeals Committee shall be by vote of a majority of the members of the Employee Benefit Appeals Committee (whether telephonic, in person or some other form), or in writing without a meeting, and effectively evidenced by the signature of any member who is so authorized by the Employee Benefit Appeals Committee.

J. A new Section 1.06B of the Plan is added to read as follows:

1.06B Employee Benefit Committee shall mean the Employee Benefit Committee, as referred to in Section 3.02C.

K. A new Section 1.06C is added to read as follows:

1.06C Employer shall mean the COMPANY, PG&E Corporation, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., and any other company or association designated pursuant to Section 3.02B(a)(2).

L. A new Section 1.06D is added to read as follows:

1.06D ERISA shall mean the Employee Retirement Income Security Act of 1974, as amended.

M. Section 1.07 of the Plan is amended to read as follows:

1.07 Group Life Insurance Plan shall mean the Pacific Gas and Electric Company Group Life Insurance Plan, restated June 1, 2013, as amended from time to time.

N. Section 1.08 of the Plan is amended to read as follows:

1.08 Management Employee shall mean an employee of the COMPANY or of an EMPLOYER who is employed in a monthly paid position, but who is not in a collective bargaining unit.

O. Section 1.11 of the Plan is amended to read as follows:

1.11 Plan Administrator shall mean the EMPLOYEE BENEFIT COMMITTEE, 1850 Gateway Blvd., Room 7025, Concord, CA, 94520.

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P. A new Section 1.11A of the Plan is added to read as follows:

1.11A Retirement Plan shall mean The Pacific Gas and Electric Company Retirement Plan, restated January 1, 2014, as amended from time to time.

Q. Section 1.12 of the Plan is amended to read as follows:

1.12 Service shall mean the "credited service" as that term is defined in the RETIREMENT PLAN or, if the Compensation Committee of the Board of Directors of PG&E Corporation has granted an adjusted service date for an eligible employee, "credited service" as calculated from such adjusted service date. Additionally, for purposes of this PLAN, Service shall include service with any EMPLOYER.

R. A new Section 1.12A is added to read as follows:

1.12A Summary of Material Modification shall mean a notice of amendment or change required by ERISA, when the PLAN has been amended or when other information is required to appear in the PLAN's SUMMARY PLAN DESCRIPTION.

S. A new Section 1.12B is added to read as follows:

1.12B Summary Plan Description shall mean the most recent "Summary of Benefits Handbook for Retirees and Surviving Dependents," as modified by subsequent Summaries of Material Modifications.

T. A new Section 1.12C is added to read as follows:

1.12C Trusts shall mean the trusts that may be established to fund certain benefits under the PLAN.

U. A new Section 1.12D is added to read as follows:

1.12D Trustee shall mean such bank or trust company selected by the EMPLOYEE BENEFIT COMMITTEE which agrees to act as trustee or successor trustee pursuant to the TRUST AGREEMENT.

V. A new Section 1.12E is added to read as follows:

1.12E Trust Agreement shall mean a written agreement among the COMPANY, the EMPLOYEE BENEFIT COMMITTEE and the TRUSTEE governing the provision of trustee services to the PLAN.

W. Section 1.13 is amended to read as follows:

1.13 Weekly-Paid Non-Bargaining Unit Employee shall mean an employee of the COMPANY or an EMPLOYER, but who is paid on a weekly basis and is not a member of a collective bargaining unit.

X. Section 2.02 of the Plan is amended to read as follows:

2.02 Terminated Employees. Anything the PLAN to the contrary notwithstanding, an employee whose employment with the COMPANY or an EMPLOYER terminates prior to attaining "Normal Retirement Date" or "Early Retirement Date," as those terms are defined under the RETIREMENT PLAN, shall not be an eligible employee entitled to benefits under the PLAN.

Y. Section 3.02 of the Plan is amended to read as follows:

3.02 Designation of Beneficiary. An eligible employee who has elected a form of benefit providing for the payment of life insurance proceeds upon his death shall designate a BENEFICIARY, or change such BENEFICIARY, by filling out a form provided by, and filed with, the PLAN ADMINISTRATOR for this purpose. The designation of a BENEFICIARY becomes effective only when received by the PLAN ADMINISTRATOR. If there is no designation of a BENEFICIARY on file with the PLAN ADMINISTRATOR, the BENEFICIARY shall be in accordance with the eligible employee's designation of a beneficiary for the purposes of the GROUP LIFE INSURANCE PLAN. If the designated BENEFICIARY is not living at the time of the eligible employee's death, the PLAN ADMINISTRATOR shall determine the individual, individuals, or estate entitled to receive benefits by application of the procedures set out in the GROUP LIFE INSURANCE PLAN.

Z. A new Section 3.02A of the Plan is added to read as follows:

3.02A Funding and Expenses.

(a) Costs of Benefits. The cost of benefits under the PLAN may be funded by EMPLOYER contributions (from the general assets or by payment through one or more TRUSTS). Each EMPLOYER is responsible for making contributions to the PLAN on behalf of its eligible employees, or for reimbursing the COMPANY for the cost of such contributions, as provided in Section 3.02B(a)(3), as determined by the [PLAN ADMINISTRATOR] in its sole discretion. In the event an EMPLOYER fails to make its allocable share of any contribution, and the COMPANY does not exercise its discretion to make the contribution on such EMPLOYER's behalf, participation in the PLAN of the eligible employees of such EMPLOYER will be suspended to the extent permitted under applicable law. If, at some future date, the EMPLOYER makes all past-due contributions, the participation of its eligible employees will be recognized for the period of suspension.

(b) Use of Trusts. The Company may, but is not required to, establish one or more TRUSTS for the payment of benefits under the PLAN.

(c) Liability for Benefit Costs Under Insurance Agreements. If a benefit under the PLAN is insured under an agreement with an insurance company, then the EMPLOYERS assume no liability or responsibility therefor. Any person having a right or claim shall look solely to the insurance company that is obliged to provide such benefits.

(d) Plan Expenses. The expenses incurred in administering the PLAN shall be borne by the EMPLOYERS or by the TRUSTS used to fund the benefits under the PLAN. The EMPLOYERS' liability for the expenses of PLAN administration, to the extent applicable, may be equitably apportioned among the EMPLOYERS, as determined by the EMPLOYEE BENEFIT COMMITTEE (solely in a settlor capacity) in its sole discretion. Such permissible expenses that may be borne by the TRUSTS shall, to the extent consistent with ERISA, include any expenses incident to the functioning of the PLAN ADMINISTRATOR or any department of the EMPLOYERS, including, but not limited to, fees for accountants, actuaries, counsel, investment managers and other specialists and their agents and other costs of administering the PLAN. The EMPLOYERS may seek reimbursement from the TRUSTS, if any, for expenses of administering this PLAN, to the extent applicable and permitted by the CODE and ERISA. A refund, rebate, performance guarantee penalty or similar item related to the operation of the PLAN may be paid directly to the COMPANY's operating general assets or to the TRUSTS as designated by the PLAN ADMINISTRATOR in its sole discretion as permitted under ERISA or the CODE. The expenses of a CLAIM ADMINISTRATOR shall be borne by the CLAIM ADMINISTRATOR, the COMPANY or the TRUSTS, as provided in the applicable agreement with the CLAIM ADMINISTRATOR, as permitted under the CODE or ERISA.

AA. A new Section 3.02B of the Plan is added to read as follows:

3.02B Company's Settlor Powers.

(a) Company Powers. The COMPANY, acting through its BOARD OF DIRECTORS or any duly authorized committee of the BOARD OF DIRECTORS, or the Board of Directors (or any committee thereof) of PG&E Corporation, shall have the following powers:

(1) Amend or Terminate the Plan. The power to amend or terminate the PLAN.

(2) Designation and Removal of Employers. The power to designate and remove the EMPLOYERS whose eligible employees may participate in the PLAN.

(3) Contribution to the Plan. The power to contribute to the PLAN, or as applicable, TRUSTS, such amount of contributions as the COMPANY shall determine in its sole discretion.

(b) Discretionary Delegation of Settlor Powers. The COMPANY, acting through its BOARD OF DIRECTORS or any duly authorized committee of the BOARD OF DIRECTORS, or the Board of Directors (or any committee thereof) of PG&E Corporation, may delegate any of its powers described in Section 3.02B(a), including, but not limited to, to the BOARD OF DIRECTORS, or any committee thereof, of the COMPANY, to the Board of Directors, or any committee thereof, of PG&E Corporation, or to an officer of either the COMPANY or PG&E Corporation. Any use of such powers by a delegate of the BOARD OF DIRECTORS of the COMPANY or the Board of Directors of PG&E Corporation, as the case may be, shall have the same force and effect as if utilized by the BOARD OF DIRECTORS of the COMPANY or the Board of Directors of PG&E Corporation, as the case may be, and shall be considered a settlor and non-fiduciary activity by the delegate.

(c) Delegation of Settlor Authority to the Employee Benefit Committee. The EMPLOYEE BENEFIT COMMITTEE, in a settlor capacity, is authorized to adopt amendments that, as determined by the EMPLOYEE BENEFIT COMMITTEE in its sole discretion, are:

(1) Required by Law. Required to comply with applicable law; or

(2) Amendments Not Materially Impacting Plan Benefits, Rights or Features or Benefit Structures. Amendments that improve the operation of the PLAN but that do not affect the governance structure of the PLAN and do not have a material effect on PLAN benefits, rights or features.

(d) Prohibited Amendments. Notwithstanding the foregoing, no amendment shall:

(1) Authorize or permit any part of the TRUST (other than such part as is required to pay taxes and PLAN expenses consistent with applicable law) to be used for or diverted other than for the exclusive benefit of the eligible employees or their BENEFICIARIES prior to the satisfaction of all liabilities with respect to the eligible employees or their BENEFICIARIES;

(2) Diminish any benefits arising from incurred but unpaid claims for benefits of eligible employees prior to the effective date of such amendment; or

(3) Cause or permit any portion of the TRUST to revert to or become the property of any EMPLOYER except to the extent permitted under applicable law.

BB. A new Section 3.02C of the Plan is added to read as follows:

3.02C Employee Benefit Committee.

(a) Composition of the Employee Benefit Committee. The Chief Financial Officer of PG&E Corporation, the General Counsel of PG&E Corporation and the Executive Vice President, Corporate Services and Human Resources, of PG&E Corporation shall be members of the EMPLOYEE BENEFIT COMMITTEE and shall designate two additional members of the EMPLOYEE BENEFIT COMMITTEE who shall be officers or employees of the PG&E Corporation or its subsidiaries. If there is no Executive Vice President, Corporate Services and Human Resources of PG&E Corporation, then the senior most human resources officer of the COMPANY (or, if such role is vacant, the equivalent position at PG&E Corporation) will instead be a member of the EMPLOYEE BENEFIT COMMITTEE. The EMPLOYEE BENEFIT COMMITTEE shall designate one of its members to serve as its Chairman.

(b) Quorum. A quorum of the EMPLOYEE BENEFIT COMMITTEE shall consist of three members.

(c) Action by the Employee Benefit Committee. Action of the EMPLOYEE BENEFIT COMMITTEE shall be by vote of a majority of the members of the EMPLOYEE BENEFIT COMMITTEE present at a meeting, or in writing without a meeting and evidenced by the signature of the Chairman of the EMPLOYEE BENEFIT COMMITTEE or any member who is so authorized by the EMPLOYEE BENEFIT COMMITTEE or its Chairman.

CC. Section 3.03 of the Plan is amended to read as follows:

3.03 Plan Administration.

(a) Plan Administrator and Named Fiduciary. The EMPLOYEE BENEFIT COMMITTEE serves as the PLAN ADMINISTRATOR. The PLAN ADMINISTRATOR is the "named fiduciary," within the meaning of Section 402(a)(2) of ERISA, of the PLAN, but only with respect to its duties and powers as PLAN ADMINISTRATOR. For purposes of clarity, the EMPLOYEE BENEFIT COMMITTEE is not a fiduciary for any other purpose, including, but not limited to, the duties and powers allocated to others, as provided in Section 3.03(f) and 3.03(g), below.

(b) Plan Administrator Duties and Powers. To the extent not the responsibility of a CLAIM ADMINISTRATOR or some other entity, the PLAN ADMINISTRATOR shall have the discretionary authority with respect to all duties necessary or powers desirable to administer the PLAN, including, but not limited to, the following:

(1) To interpret all provisions of the PLAN and to establish reasonable rules and procedures to facilitate the administration of the PLAN;

(2) To communicate the terms of the PLAN to eligible employees and BENEFICIARIES;

(3) To prescribe procedures and related forms (which may be electronic in nature) to be followed by eligible employees and BENEFICIARIES filing claims for benefits under the PLAN;

(4) To receive from eligible employees and BENEFICIARIES such information as shall be necessary for the proper administration of the PLAN;

(5) To keep records related to the PLAN, including records related to claims for benefits filed and paid under the PLAN, and any other information required by the CODE and ERISA;

(6) To enter into appropriate agreements with, appoint, discharge and periodically monitor the performance of third party administrators, insurers, service providers, investment managers, consultants, accountants, attorneys and other agents in the administration of the PLAN;

(7) To prepare and file any reports or returns with respect to the PLAN required by the CODE and ERISA;

(8) To correct errors and make equitable adjustments for mistakes made in the administration of the PLAN, including, but not limited to, for mistakes made in the payment or nonpayment of benefits under the PLAN, specifically, and without limitation, to recover erroneous overpayments made by the PLAN to an eligible employee or BENEFICIARY, in whatever manner the PLAN ADMINISTRATOR deems appropriate, including suspensions or recoupment of, or offsets against, future payments, including benefit payments or wages, due that eligible employee or BENEFICIARY;

(9) To issue rules and regulations necessary for the proper conduct and administration of the PLAN and to change, alter or amend such rules and regulations;

(10) To determine all questions arising in the administration of the PLAN, to the extent the determination is not the responsibility of a third party administrator, insurer or some other entity;

(11) To propose and accept settlements and offsets of claims, overpayments and other disputes involving claims for benefits under the PLAN;

(12) To direct the TRUSTEE to pay benefits and PLAN expenses chargeable to the PLAN;

(13) To determine and charge to each EMPLOYER its share of the EMPLOYER contributions made by the COMPANY;

(14) To determine and enforce any limits on benefit elections hereunder;

(15) To compute the amount and kind of benefits payable to eligible employees and BENEFICIARIES, to the extent such determination is not the responsibility of a third party administrator, insurer or some other entity; and

(16) Such other duties or powers provided in the PLAN or necessary to administer the PLAN.

(c) Allocation and Delegation of Duties and Powers. The PLAN ADMINISTRATOR shall have the authority to:

(1) Allocation of Duties and Powers. Allocate, from time-to-time, by a written instrument filed in its records, all or any part of its duties and powers under the PLAN to one or more of its members, including a subcommittee, as may be deemed advisable, and in the same manner to revoke such allocation of duties and powers. In the exercise of such allocated duties and powers, any action of the member or subcommittee to whom duties and powers are allocated shall have the same force and effect for all purposes hereunder as if such action had been taken by the PLAN ADMINISTRATOR and shall be afforded the same deference and arbitrary and capricious level of review afforded to the PLAN ADMINISTRATOR. The PLAN ADMINISTRATOR shall not be liable for any acts or omissions of such member or subcommittee. The member or subcommittee to whom duties and powers have been allocated shall periodically report to the PLAN ADMINISTRATOR concerning the discharge of the allocated duties and powers.

(2) Delegation of Duties and Powers. Delegate, from time-to-time, by a written instrument filed in its records, all or any part of its duties and powers under the PLAN to such person or persons, as the PLAN ADMINISTRATOR may deem advisable (and may authorize such person to delegate such duties and powers to such other person or persons as the PLAN ADMINISTRATOR shall authorize) and in the same manner to revoke any such delegation of duties and powers. Any action of the delegate in the exercise of such delegated duties and powers shall have the same force and effect for all purposes hereunder as if such action had been taken by the PLAN ADMINISTRATOR and shall be afforded the same deference and arbitrary and capricious level of review afforded to the PLAN ADMINISTRATOR. The PLAN ADMINISTRATOR shall not be liable for any acts or omissions of any such delegate. The delegate shall periodically report to the PLAN ADMINISTRATOR concerning the discharge of the delegated duties and powers.

(3) Deemed Delegation of Duties and Powers. The PLAN ADMINISTRATOR shall be deemed to have delegated its duties and powers for determining benefits, eligibility for benefits and/or other PLAN operations to a third party administrator, insurer or other person where such person has been appointed by the PLAN ADMINISTRATOR or its delegate to make such determinations. In such case, such other person shall have the duties and powers as the PLAN ADMINISTRATOR as set forth in this PLAN document. Any action of the delegate in the exercise of such delegated duties and powers shall have the same force and effect for all purposes hereunder as if such action had been taken by the PLAN ADMINISTRATOR and shall be afforded the same deference and arbitrary and capricious level of review afforded to the PLAN ADMINISTRATOR.

(d) Claim Administrators. Each CLAIM ADMINISTRATOR is a "named fiduciary," within the meaning of Section 402(a)(2) of ERISA, of the Plan, but only with respect to its duties and powers as CLAIM ADMINISTRATOR. For purposes of clarity, a CLAIM ADMINISTRATOR is not a fiduciary for any other purpose, including, but not limited to, the duties allocated to others, as provided in Section 3.03(b) and Section 3.03(g). The PLAN ADMINISTRATOR shall have no responsibility for reviewing claims for benefits that are required by the terms of the applicable agreement to be processed by the CLAIM ADMINISTRATOR.

(e) Claim Administrator Duties and Powers. A CLAIM ADMINISTRATOR shall have all duties and powers necessary or desirable to handle the day-to-day administration of benefits under the PLAN, which would include the discretionary authority to interpret and decide all matters of fact in granting or denying benefits under the PLAN. The CLAIM ADMINISTRATOR's interpretations and decisions shall be final and conclusive on all persons claiming benefits under the PLAN. For purposes of clarity, if a benefit is provided through an insurance contract, any claim that is required by the terms of the insurance contract to be processed by an insurance company shall be made in writing to the insurance company.

(f) Named Fiduciary for Initial Claims and Appeals Relating to Benefit Determinations and Initial Claims Relating to Eligibility Determinations under Section 3.04. The CLAIM ADMINISTRATOR is the "named fiduciary," within the meaning of Section 402(a)(2) of ERISA, for purposes of exercising its discretionary authority in deciding initial claims and appeals of claims not related to questions of length of SERVICE, status or membership in the PLAN, as described in Section 3.04. For purposes of clarity, the CLAIM ADMINISTRATOR is not a fiduciary for any other purpose.

(g) Named Fiduciary for Appeals of Eligibility Determinations under Section 3.04. The EMPLOYEE BENEFIT APPEALS COMMITTEE is the "named fiduciary," within the meaning of Section 402(a)(2) of ERISA, for purposes of exercising its discretionary authority in determining appeals of claims for benefits under the PLAN involving questions of length of SERVICE, status or membership in the PLAN. For purposes of clarity, the EMPLOYEE BENEFIT APPEALS COMMITTEE is not a fiduciary for any other purpose.

(h) Indemnification and Exculpation.

(1) Scope. The PLAN shall indemnify and exculpate any current and former director, officer and employee of the COMPANY, as well as current and former members of the EMPLOYEE BENEFIT COMMITTEE, EMPLOYEE BENEFIT APPEALS COMMITTEE and BENEFITS ("COVERED PERSONS") against any and all claims of liability and investigations brought against the COVERED PERSON arising in connection with the exercise of the COVERED PERSON's duties and powers to the PLAN, including all expenses (including reasonable attorneys' fees) reasonably incurred in the COVERED PERSON's defense of the claims of liability or investigations, unless (i) the COVERED PERSON has committed gross negligence, fraud or breach of fiduciary duty under ERISA with respect to the claims of liability or investigations, as determined in a non-appealable judgment of a court of competent jurisdiction or as set forth in a legal opinion issued by independent counsel to the EMPLOYEE BENEFIT COMMITTEE or (ii) indemnification or exculpation would violate applicable law.

(2) Advancement of Expenses. The PLAN may advance all expenses (including reasonable attorneys' fees) reasonably incurred by a COVERED PERSON in the defense against claims of liability or investigations brought against the COVERED PERSON arising in connection with the exercise of the COVERED PERSON's duties and powers to the PLAN; provided that, the EMPLOYERS shall have the right, but not the obligation, to conduct the defense of such COVERED PERSON. Any advance to a COVERED PERSON must be conditioned upon delivery to the PLAN (or if the expenses are advanced by an EMPLOYER, then to such EMPLOYER) of an undertaking by, or on behalf of, the COVERED PERSON to repay all such amounts to the PLAN (or if the expenses are advanced by an EMPLOYER, then to such EMPLOYER) if it is ultimately determined that the COVERED PERSON is not entitled to indemnification and exculpation in accordance with Section 3.03(h)(1).

(3) Certain Claims of Liability. Provided that the COVERED PERSON is otherwise entitled to be indemnified and exculpated in accordance with Section 3.03(h)(1), the PLAN may only indemnify the COVERED PERSON for reasonably incurred legal expenses (including reasonable attorneys' fees) in respect of claims of liability brought by the PLAN, the TRUSTEE or an EMPLOYER against the COVERED PERSON to the maximum extent permitted by law. Notwithstanding Section 3.03(h)(2), the PLAN may not advance any expenses to the COVERED PERSON in respect of claims of liability brought by the PLAN or brought by the TRUSTEE against the COVERED PERSON. For purposes hereof, claims of liability "brought by the PLAN" means those claims initiated by the EMPLOYEE BENEFIT COMMITTEE.

(4) Source of Indemnification and Exculpation. The EMPLOYERS, in their sole discretion, may indemnify, exculpate and advance the expenses (including reasonable attorneys' fees) of COVERED PERSONS, as provided in this Section 3.03(h). The EMPLOYERS may satisfy these obligations through the purchase of a policy or policies of insurance providing equivalent protection, which shall be considered primary to any funds that may be provided by the EMPLOYERS or the PLAN to the extent that an insurance company grants coverage with respect to any claim or investigation subject to the scope set forth in Section 3.03(h)(1). The EMPLOYERS' liability for the expenses of COVERED PERSONS, to the extent applicable, may be equitably apportioned among the EMPLOYERS, including any EMPLOYER that subsequently ceases to be an EMPLOYER, as determined by the PG&E Corporation Board of Directors, or any of its committees, in its sole discretion.

DD. Section 3.04 of is amended to read as follows:

3.04 Claims and Appeals Procedure.

(a) Compliance with Regulations. It is intended that the claims procedure of this PLAN be administered in accordance with the claims procedure regulations of the U.S. Department of Labor set forth in 29 C.F.R. Section 2560.503-1.

(b) Initial Claims

(1) Submission of Initial Claims Relating to the Payment of Plan Benefits. Claims for benefits under the PLAN made by an eligible employee, BENEFICIARY or other person covered or claiming they are entitled to benefits from the PLAN ("CLAIMANT") (or by an authorized representative of any CLAIMANT) must be submitted in writing to the CLAIM ADMINISTRATOR.

(2) Submission of Initial Claims Relating to Eligibility. Claims relating to length of SERVICE, status or membership in the PLAN made by a CLAIMANT (or by an authorized representative of such CLAIMANT) must be submitted in writing to the CLAIM ADMINISTRATOR.

(3) Authorized Representative. The PLAN ADMINISTRATOR may establish and enforce reasonable procedures for determining whether any individual or entity has been authorized to act on behalf of a CLAIMANT.

(4) Processing of Approved Claims. Approved claims will be processed and, if applicable, the PLAN ADMINISTRATOR will issue instructions for the provision of benefits as approved.

(5) Notification of Denied Claims. If a claim is denied in whole or in part by the CLAIM ADMINISTRATOR in its discretion, the CLAIM ADMINISTRATOR shall notify the CLAIMANT of the decision by written or electronic notice, in a manner calculated to be understood by the CLAIMANT. The notice shall set forth:

a) The specific reasons for the denial of the claim;

b) A reference to specific provisions of the PLAN on which the denial is based;

c) A description of any additional material or information necessary to perfect the claim and an explanation of why such material or information is necessary; and

d) An explanation of the PLAN's claims review procedure for the denied or partially denied claim and any applicable time limits, and a statement that the CLAIMANT has a right to bring a civil action under Section 502(a) of ERISA following an adverse benefit determination on review.

Such notification shall be given within 90 days after the claim is received by the CLAIM ADMINISTRATOR (or within 180 days, if special circumstances require an extension of time for processing the claim, and provided that written notice of such extension and circumstances and the date a decision is expected is given to the CLAIMANT within the initial 90-day period). A claim is considered approved only if its approval is communicated in writing to a CLAIMANT.

(c) Appeals of Denied Claims.

(1) Right to Appeal Benefit Determinations. Upon denial of a claim in whole or in part for benefits under the PLAN, or failure of the CLAIM ADMINISTRATOR to provide a notice of denial as set forth in Section 3.04(b)(5), a CLAIMANT or his or her duly authorized representative shall have the right to submit a written request to the CLAIM ADMINISTRATOR for a full and fair review of the denied claim. A request for review of a claim must be submitted within 60 days of receipt by the CLAIMANT of written notice of the denial of the claim. If the CLAIMANT fails to file a request for review within 60 days of the denial notification, the claim will be deemed abandoned and the CLAIMANT precluded from reasserting it.

(2) Right to Appeal Eligibility Determinations. Upon denial of a claim in whole or in part relating to length of SERVICE, status or membership in the PLAN, or failure of the CLAIM ADMINISTRATOR to provide a notice of denial as set forth in Section 3.04(b)(5), a CLAIMANT or his or her duly authorized representative shall have the right to submit a written request to the EMPLOYEE BENEFIT APPEALS COMMITTEE for a full and fair review of the denied claim. A request for review of a claim must be submitted within 90 days of receipt by the CLAIMANT of written notice of the denial of the claim. If the CLAIMANT fails to file a request for review within 90 days of the denial notification, the claim will be deemed abandoned and the CLAIMANT precluded from reasserting it.

(3) Access to Documents and Records. The CLAIMANT or the CLAIMANT's representative shall have, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the CLAIMANT's claim.

(4) Right to Submit Additional Information. The CLAIMANT may submit written comments, documents, records and other information relating to the claim.

(5) Scope of the Review. The review process shall include all comments, documents, records and other information submitted by the CLAIMANT relating to the claim, without regard to whether such information was submitted or considered in the initial determination.

(6) Preclusion for Materials Not Submitted. Failure to raise issues or present evidence on review will preclude those issues or evidence from being presented in any subsequent proceeding or judicial review of the claim.

(7) Decision on Review. The decision on review shall be in written or electronic form, in a manner calculated to be understood by the CLAIMANT. If the claim is denied on review, the notice shall set forth:

a) The specific reasons for the denial of the appeal of the claim;

b) A reference to specific provisions of the PLAN on which the denial is based;

c) A statement that the CLAIMANT is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the CLAIMANT's claim for benefits; and

d) A statement describing any voluntary appeal procedures offered by the PLAN (if any) and the CLAIMANT's right to obtain the information about such procedures, and a statement of the CLAIMANT's right to bring an action under Section 502(a) of ERISA.

The CLAIMANT will be advised of the results of the review within 60 days after receipt of the written request for review (or within 120 days if special circumstances require an extension of time for processing the request, and if notice of such extension and circumstances, including the date a decision is expected to be made, is given to such CLAIMANT within the initial 60 day period).

(e) Authority of Claim Administrator and Employee Benefit Appeals Committee and Deference to their Decisions. To the extent of the responsibility to review initial benefit and eligibility claims, as well as to review appeals of the denial of benefit claims (with respect to the CLAIM ADMINISTRATOR) or to review appeals of denial of claims relating to length of SERVICE, status or membership in the PLAN (with respect to the EMPLOYEE BENEFIT APPEALS COMMITTEE), then the CLAIM ADMINISTRATOR and the EMPLOYEE BENEFIT APPEALS COMMITTEE shall have the discretionary authority to interpret and apply the provisions of the PLAN and such decisions shall be afforded the maximum deference permitted by law. Benefits will be paid only if the CLAIM ADMINISTRATOR (with respect to initial benefit and eligibility claims) or the CLAIM ADMINISTRATOR or EMPLOYEE BENEFIT APPEALS COMMITTEE, on appeal, as the case may be, decides in its discretion that the CLAIMANT is so entitled. The decisions of the CLAIM ADMINISTRATOR and EMPLOYEE BENEFIT APPEALS COMMITTEE shall be final and binding on the CLAIMANT.

(f) Exhaustion of Claims Procedure Required in All Cases. Any eligible employee, BENEFICIARY or other person made subject to the claims procedures in this Section 3.04, and the SUMMARY PLAN DESCRIPTION, as modified by subsequent SUMMARIES OF MATERIAL MODIFICATION must follow and exhaust the applicable claims procedures described in this Section 3.04 before taking action in any other forum regarding a claim for benefits under the PLAN or alleging a violation of or seeking any remedy under any provision of ERISA or other applicable law.

EE. Section 3.05 of the Plan is deleted in its entirety and is hereby reserved.

FF. All references to "employer" and "participating employer" in the Plan are replaced with references to "EMPLOYER."

GG. All references to "Retirement Plan" and "COMPANY'S Retirement Plan" in the Plan are replaced with references to "RETIREMENT PLAN."

HH. All references to "GROUP LIFE INSURANCE AND LONG-TERM DISABILITY PLAN" in the Plan are replaced with references to "GROUP LIFE INSURANCE PLAN."

II. All references to "Officer" in the Plan are replaced with references to "officer."

The foregoing amendments were duly adopted by the Compensation Committee of the Board of Directors of PG&E Corporation on February 16, 2016.

JASON WELLS

Jason Wells
Chairman, Employee Benefit Committee

**EXHIBIT 12.1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| (in millions) | Three Months Ended March 31, 2016 | Year Ended December 31, 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|
| **Earnings:** | | | | | | |
| Net income | $ 108 | $ 862 | $ 1,433 | $ 866 | $ 811 | $ 845 |
| Income tax provision | (185) | (19) | 384 | 326 | 298 | 480 |
| Fixed charges | 310 | 1,260 | 1,176 | 971 | 891 | 880 |
| **Total earnings** | **$ 233** | **$ 2,103** | **$ 2,993** | **$ 2,163** | **$ 2,000** | **$ 2,205** |
| **Fixed charges:** | | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 297 | $ 1,208 | $ 1,125 | $ 917 | $ 834 | $ 824 |
| Interest on capital leases | 1 | 4 | 6 | 7 | 9 | 16 |
| AFUDC debt | 12 | 48 | 45 | 47 | 48 | 40 |
| **Total fixed charges** | **$ 310** | **$ 1,260** | **$ 1,176** | **$ 971** | **$ 891** | **$ 880** |
| **Ratios of earnings to fixed charges** | **0.75**(1) | **1.67** | **2.55** | **2.23** | **2.24** | **2.51** |

(1) The ratio of earnings to fixed charges indicates a deficiency of less than one-to-one coverage of $77 million.

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS**

| (in millions) | Three Months Ended March 31, 2016 | Year ended December 31, 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|
| **Earnings:** | | | | | | |
| Net income | $ 108 | $ 862 | $ 1,433 | $ 866 | $ 811 | $ 845 |
| Income tax provision | (185) | (19) | 384 | 326 | 298 | 480 |
| Fixed charges | 310 | 1,260 | 1,176 | 971 | 891 | 880 |
| **Total earnings** | **$ 233** | **$ 2,103** | **$ 2,993** | **$ 2,163** | **$ 2,000** | **$ 2,205** |
| **Fixed charges:** | | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 297 | $ 1,208 | $ 1,125 | $ 917 | $ 834 | $ 824 |
| Interest on capital leases | 1 | 4 | 6 | 7 | 9 | 16 |
| AFUDC debt | 12 | 48 | 45 | 47 | 48 | 40 |
| **Total fixed charges** | **$ 310** | **$ 1,260** | **$ 1,176** | **$ 971** | **$ 891** | **$ 880** |
| **Preferred stock dividends:** | | | | | | |
| Tax deductible dividends | $ 2 | $ 9 | $ 9 | $ 9 | $ 9 | $ 9 |
| Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements | 1 | 5 | 6 | 7 | 7 | 8 |
| **Total preferred stock dividends** | **3** | **14** | **15** | **16** | **16** | **17** |
| **Total combined fixed charges and preferred stock dividends** | **$ 313** | **$ 1,274** | **$ 1,191** | **$ 987** | **$ 907** | **$ 897** |
| **Ratios of earnings to combined fixed charges and preferred stock dividends** | **0.74**[1] | **1.65** | **2.51** | **2.19** | **2.21** | **2.46** |

[1] The ratio of earnings to combined fixed charges and preferred stock dividends indicates a deficiency of less than one-to-one coverage of $80 million.

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.3**
**PG&E CORPORATION**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| (in millions) | Three Months Ended March 31, 2016 | | Year Ended December 31, 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|---|
| **Earnings:** | | | | | | | |
| Net income | $ 110 | | $ 888 | $ 1,450 | $ 828 | $ 830 | $ 858 |
| Income tax provision | (187) | | (27) | 345 | 268 | 237 | 440 |
| Fixed charges | 316 | | 1,284 | 1,206 | 1,012 | 931 | 919 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | (3) | | (14) | (15) | (16) | (15) | (17) |
| **Total earnings** | **$ 236** | | **$ 2,131** | **$ 2,986** | **$ 2,092** | **$ 1,983** | **$ 2,200** |
| **Fixed charges:** | | | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 300 | | $ 1,218 | $ 1,140 | $ 942 | $ 859 | $ 846 |
| Interest on capital leases | 1 | | 4 | 6 | 7 | 9 | 16 |
| AFUDC debt | 12 | | 48 | 45 | 47 | 48 | 40 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | 3 | | 14 | 15 | 16 | 15 | 17 |
| **Total fixed charges** | **$ 316** | | **$ 1,284** | **$ 1,206** | **$ 1,012** | **$ 931** | **$ 919** |
| **Ratios of earnings to fixed charges** | **0.75** | (1) | **1.66** | **2.48** | **2.07** | **2.13** | **2.39** |

(1) The ratio of earnings to fixed charges indicates a deficiency of less than one-to-one coverage of $80 million.

Note:
For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.
Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Jason P. Wells, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

JASON P. WELLS
Jason P. Wells
Senior Vice President and Chief Financial Officer

**EXHIBIT 31.2**

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Nickolas Stavropoulos, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

NICKOLAS STAVROPOULOS

Nickolas Stavropoulos
President, Gas

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Geisha J. Williams, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

GEISHA J. WILLIAMS

Geisha J. Williams
President, Electric

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Dinyar B. Mistry, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2016

DINYAR B. MISTRY
Dinyar B. Mistry
Senior Vice President, Human Resources, Chief Financial Officer, and Controller

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2016 ("Form 10-Q"), I, Anthony F. Earley, Jr., Chairman, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ANTHONY F. EARLEY, JR.

ANTHONY F. EARLEY, JR.
Chairman, Chief Executive Officer and President

May 4, 2016

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER**
**PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2016 ("Form 10-Q"), I, Jason P. Wells, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

JASON P. WELLS

JASON P. WELLS
Senior Vice President and
Chief Financial Officer

May 4, 2016

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2016 ("Form 10-Q"), I, Nickolas Stavropoulos, President, Gas of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

NICKOLAS STAVROPOULOS

NICKOLAS STAVROPOULOS
President, Gas

May 4, 2016

## CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
## PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2016 ("Form 10-Q"), I, Geisha J. Williams, President, Electric of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

GEISHA J. WILLIAMS

GEISHA J. WILLIAMS
President, Electric

May 4, 2016

# CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2016 ("Form 10-Q"), I, Dinyar B. Mistry, Senior Vice President, Human Resources, Chief Financial Officer, and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

DINYAR B. MISTRY

DINYAR B. MISTRY
Senior Vice President, Human Resources, Chief Financial Officer, and Controller

May 4, 2016

# Exhibit 9

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C., 20549**
**FORM 10-Q**

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30,2016

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to __________

| Commission File Number | Exact Name of Registrant as Specified in its Charter | State or Other Jurisdiction of Incorporation | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E Corporation | California | 94-3234914 |
| 1-2348 | Pacific Gas and Electric Company | California | 94-0742640 |

| | |
|---|---|
| PG&E Corporation<br>77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177 | Pacific Gas and Electric Company<br>77 Beale Street<br>P.O. Box 770000<br>San Francisco, California94177 |

Address of principal executive offices, including zip code

| | |
|---|---|
| PG&E Corporation<br>(415) 973-1000 | Pacific Gas and Electric Company<br>(415) 973-7000 |

Registrant's telephone number, including area code

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. [X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation: | [X] Yes [ ] No |
| Pacific Gas and Electric Company: | [X] Yes [ ] No |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | | |
|---|---|---|
| PG&E Corporation: | [X] Large accelerated filer | [ ] Accelerated filer |
| | [ ] Non-accelerated filer | [ ] Smaller reporting company |
| Pacific Gas and Electric Company: | [ ] Large accelerated filer | [ ] Accelerated filer |
| | [X] Non-accelerated filer | [ ] Smaller reporting company |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

| | |
|---|---|
| PG&E Corporation: | [ ] Yes [X] No |
| Pacific Gas and Electric Company: | [ ] Yes [X] No |

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding as of October 24,2016:

| | |
|---|---|
| PG&E Corporation: | 505,666,694 |
| Pacific Gas and Electric Company: | 264,374,809 |

**PG&E CORPORATION AND**
**PACIFIC GAS AND ELECTRIC COMPANY**
**FORM 10-Q**
**FOR THE QUARTERLY PERIOD ENDEDSEPTEMBER 30,2016**

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**GLOSSARY**

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|---|---|
| 2015 Form 10-K | PG&E Corporation and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2015 |
| 2016 Q1 Form 10-Q | PG&E Corporation and Pacific Gas and Electric Company's combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 |
| 2016 Q2 Form 10-Q | PG&E Corporation and Pacific Gas and Electric Company's combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 |
| AFUDC | allowance for funds used during construction |
| ALJ | Administrative Law Judge |
| ARO(s) | asset retirement obligation(s) |
| ASU | Accounting Standards Update issued by the FASB (see below) |
| Cal Fire | California Department of Forestry and Fire Protection |
| CAISO | California Independent System Operator Corporation |
| Central Coast Water Board | Central Coast Regional Water Quality Control Board |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DER | distributed energy resources |
| Diablo Canyon | Diablo Canyon nuclear power plant |
| DOI | U.S. Department of the Interior |
| DTSC | California Department of Toxic Substances Control |
| EMANI | European Mutual Association for Nuclear Insurance |
| Energy Division | CPUC's Energy Division |
| EPS | earnings per common share |
| EV | electric vehicle |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| GWH | gigawatt-hours |
| IOU(s) | investor-owned utility(ies) |
| MOD POD | modified presiding officer's decision |
| NAV | net asset value |
| NDCTP | Nuclear Decommissioning Cost Triennial Proceedings |
| NEIL | Nuclear Electric Insurance Limited |
| NEM | Net Energy Metering |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| OII | order instituting investigation |
| ORA | Office of Ratepayer Advocates |
| POD | presiding officer's decision |
| PSEP | pipeline safety enhancement plan |
| PV | photovoltaic |
| Regional Board | California Regional Water Control Board, Lahontan Region |
| RPS | Renewable Portfolio Standards |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD |
| TO | transmission owner |

| | |
|---|---|
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

| | (Unaudited) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (in millions, except per share amounts) | 2016 | 2015 | 2016 | 2015 |
| **Operating Revenues** | | | | |
| Electric | $ 3,994 | $ 3,868 | $ 10,590 | $ 10,344 |
| Natural gas | 816 | 682 | 2,363 | 2,322 |
| **Total operating revenues** | **4,810** | **4,550** | **12,953** | **12,666** |
| **Operating Expenses** | | | | |
| Cost of electricity | 1,613 | 1,681 | 3,719 | 3,958 |
| Cost of natural gas | 80 | 50 | 377 | 442 |
| Operating and maintenance | 1,783 | 1,621 | 5,631 | 5,028 |
| Depreciation, amortization, and decommissioning | 694 | 653 | 2,090 | 1,935 |
| **Total operating expenses** | **4,170** | **4,005** | **11,817** | **11,363** |
| **Operating Income** | **640** | **545** | **1,136** | **1,303** |
| Interest income | 8 | 2 | 17 | 6 |
| Interest expense | (211) | (194) | (621) | (575) |
| Other income, net | 24 | 24 | 74 | 100 |
| **Income Before Income Taxes** | **461** | **377** | **606** | **834** |
| Income tax provision (benefit) | 70 | 67 | (105) | 84 |
| **Net Income** | **391** | **310** | **711** | **750** |
| Preferred stock dividend requirement of subsidiary | 3 | 3 | 10 | 10 |
| **Income Available for Common Shareholders** | **$ 388** | **$ 307** | **$ 701** | **$ 740** |
| **Weighted Average Common Shares Outstanding, Basic** | **501** | **486** | **497** | **481** |
| **Weighted Average Common Shares Outstanding, Diluted** | **503** | **489** | **500** | **484** |
| **Net Earnings Per Common Share, Basic** | **$ 0.77** | **$ 0.63** | **$ 1.41** | **$ 1.54** |
| **Net Earnings Per Common Share, Diluted** | **$ 0.77** | **$ 0.63** | **$ 1.40** | **$ 1.53** |
| **Dividends Declared Per Common Share** | **$ 0.49** | **$ 0.46** | **$ 1.44** | **$ 1.37** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | (Unaudited) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (in millions) | 2016 | 2015 | 2016 | 2015 |
| **Net Income** | $ 391 | $ 310 | $ 711 | $ 750 |
| **Other Comprehensive Income** | | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $0, $0 and $0, at respective dates) | - | - | - | - |
| Net change in investments (net of taxes of $0, $0, $0 and $12, at respective dates) | - | - | - | (17) |
| **Total other comprehensive income (loss)** | - | - | - | (17) |
| **Comprehensive Income** | 391 | 310 | 711 | 733 |
| **Preferred stock dividend requirement of subsidiary** | 3 | 3 | 10 | 10 |
| **Comprehensive Income Attributable to Common Shareholders** | $ 388 | $ 307 | $ 701 | $ 723 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

| (in millions) | (Unaudited) Balance At September 30, 2016 | December 31, 2015 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 71 | $ 123 |
| Restricted cash | 168 | 234 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $53 and $54 at respective dates) | 1,233 | 1,106 |
| Accrued unbilled revenue | 956 | 855 |
| Regulatory balancing accounts | 1,475 | 1,760 |
| Other | 475 | 286 |
| Regulatory assets | 370 | 517 |
| Inventories: | | |
| Gas stored underground and fuel oil | 134 | 126 |
| Materials and supplies | 343 | 313 |
| Income taxes receivable | 218 | 155 |
| Other | 306 | 338 |
| **Total current assets** | **5,749** | **5,813** |
| **Property, Plant, and Equipment** | | |
| Electric | 51,532 | 48,532 |
| Gas | 17,384 | 16,749 |
| Construction work in progress | 2,117 | 2,059 |
| Other | 2 | 2 |
| **Total property, plant, and equipment** | **71,035** | **67,342** |
| Accumulated depreciation | (21,605) | (20,619) |
| **Net property, plant, and equipment** | **49,430** | **46,723** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,534 | 7,029 |
| Nuclear decommissioning trusts | 2,597 | 2,470 |
| Income taxes receivable | 70 | 135 |
| Other | 1,185 | 1,064 |
| **Total other noncurrent assets** | **11,386** | **10,698** |
| **TOTAL ASSETS** | **$ 66,565** | **$ 63,234** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions, except share amounts) | September 30, 2016 | December 31, 2015 |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 1,145 | $ 1,019 |
| Long-term debt, classified as current | 160 | 160 |
| Accounts payable: | | |
| Trade creditors | 1,370 | 1,414 |
| Regulatory balancing accounts | 764 | 715 |
| Other | 496 | 398 |
| Disputed claims and customer refunds | 233 | 454 |
| Interest payable | 144 | 206 |
| Other | 1,958 | 1,997 |
| **Total current liabilities** | **6,270** | **6,363** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 16,528 | 15,925 |
| Regulatory liabilities | 6,613 | 6,321 |
| Pension and other postretirement benefits | 2,632 | 2,622 |
| Asset retirement obligations | 4,672 | 3,643 |
| Deferred income taxes | 9,850 | 9,206 |
| Other | 2,394 | 2,326 |
| **Total noncurrent liabilities** | **42,689** | **40,043** |
| **Commitments and Contingencies (Note 9)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 505,183,752 and 492,025,443 shares outstanding at respective dates | 12,083 | 11,282 |
| Reinvested earnings | 5,278 | 5,301 |
| Accumulated other comprehensive loss | (7) | (7) |
| **Total shareholders' equity** | **17,354** | **16,576** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **17,606** | **16,828** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 66,565** | **$ 63,234** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | (Unaudited) | |
|---|---|---|
| | Nine Months Ended September 30, | |
| (in millions) | 2016 | 2015 |
| **Cash Flows from Operating Activities** | | |
| Net income | $ 711 | $ 750 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 2,090 | 1,935 |
| Allowance for equity funds used during construction | (84) | (80) |
| Deferred income taxes and tax credits, net | 644 | 260 |
| Disallowed capital expenditures | 517 | 270 |
| Other | 293 | 247 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | (546) | (322) |
| Inventories | (38) | 5 |
| Accounts payable | 189 | 95 |
| Income taxes receivable/payable | (63) | 42 |
| Other current assets and liabilities | 254 | (87) |
| Regulatory assets, liabilities, and balancing accounts, net | (634) | 78 |
| Other noncurrent assets and liabilities | (85) | (251) |
| **Net cash provided by operating activities** | **3,248** | **2,942** |
| **Cash Flows from Investing Activities** | | |
| Capital expenditures | (4,128) | (3,662) |
| Decrease in restricted cash | 66 | 11 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,019 | 1,023 |
| Purchases of nuclear decommissioning trust investments | (1,050) | (1,124) |
| Other | 10 | 18 |
| **Net cash used in investing activities** | **(4,083)** | **(3,734)** |
| **Cash Flows from Financing Activities** | | |
| Net issuances (repayments) of commercial paper, net of discount of $5 and $2 at respective dates | (128) | 545 |
| Short-term debt financing | 250 | - |
| Short-term debt matured | - | (300) |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 and $14 at respective dates | 594 | 486 |
| Common stock issued | 727 | 689 |
| Common stock dividends paid | (678) | (638) |
| Other | 18 | 13 |
| **Net cash provided by financing activities** | **783** | **795** |
| **Net change in cash and cash equivalents** | **(52)** | **3** |
| **Cash and cash equivalents at January 1** | **123** | **151** |
| **Cash and cash equivalents at September 30** | **$ 71** | **$ 154** |

| | | | | |
|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | |
| Cash received (paid) for: | | | | |
| Interest, net of amounts capitalized | $ | (611) | $ | (569) |
| Income taxes, net | | 154 | | - |
| **Supplemental disclosures of noncash investing and financing activities** | | | | |
| Common stock dividends declared but not yet paid | $ | 248 | $ | 223 |
| Capital expenditures financed through accounts payable | | 325 | | 245 |
| Noncash common stock issuances | | 15 | | 15 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

| | (Unaudited) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| **(in millions)** | **2016** | **2015** | **2016** | **2015** |
| **Operating Revenues** | | | | |
| Electric | $ 3,993 | $ 3,868 | $ 10,590 | $ 10,344 |
| Natural gas | 816 | 682 | 2,363 | 2,322 |
| **Total operating revenues** | **4,809** | **4,550** | **12,953** | **12,666** |
| **Operating Expenses** | | | | |
| Cost of electricity | 1,613 | 1,681 | 3,719 | 3,958 |
| Cost of natural gas | 80 | 50 | 377 | 442 |
| Operating and maintenance | 1,782 | 1,622 | 5,630 | 5,028 |
| Depreciation, amortization, and decommissioning | 694 | 653 | 2,090 | 1,935 |
| **Total operating expenses** | **4,169** | **4,006** | **11,816** | **11,363** |
| **Operating Income** | **640** | **544** | **1,137** | **1,303** |
| Interest income | 8 | 2 | 16 | 6 |
| Interest expense | (209) | (191) | (614) | (567) |
| Other income, net | 23 | 22 | 68 | 68 |
| **Income Before Income Taxes** | **462** | **377** | **607** | **810** |
| Income tax provision (benefit) | 73 | 72 | (99) | 95 |
| **Net Income** | **389** | **305** | **706** | **715** |
| Preferred stock dividend requirement | 3 | 3 | 10 | 10 |
| **Income Available for Common Stock** | **$ 386** | **$ 302** | **$ 696** | **$ 705** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | (Unaudited) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (in millions) | 2016 | 2015 | 2016 | 2015 |
| **Net Income** | $ 389 | $ 305 | $ 706 | $ 715 |
| **Other Comprehensive Income** | | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $0, $0 and $0, at respective dates ) | - | - | 1 | - |
| **Total other comprehensive income (loss)** | - | - | 1 | - |
| **Comprehensive Income** | $ 389 | $ 305 | $ 707 | $ 715 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions) | September 30, 2016 | December 31, 2015 |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 68 | $ 59 |
| Restricted cash | 168 | 234 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $53 and $54 at respective dates) | 1,233 | 1,106 |
| Accrued unbilled revenue | 956 | 855 |
| Regulatory balancing accounts | 1,475 | 1,760 |
| Other | 473 | 284 |
| Regulatory assets | 370 | 517 |
| Inventories: | | |
| Gas stored underground and fuel oil | 134 | 126 |
| Materials and supplies | 343 | 313 |
| Income taxes receivable | 194 | 130 |
| Other | 306 | 338 |
| **Total current assets** | **5,720** | **5,722** |
| **Property, Plant, and Equipment** | | |
| Electric | 51,532 | 48,532 |
| Gas | 17,384 | 16,749 |
| Construction work in progress | 2,117 | 2,059 |
| **Total property, plant, and equipment** | **71,033** | **67,340** |
| Accumulated depreciation | (21,603) | (20,617) |
| **Net property, plant, and equipment** | **49,430** | **46,723** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 7,534 | 7,029 |
| Nuclear decommissioning trusts | 2,597 | 2,470 |
| Income taxes receivable | 70 | 135 |
| Other | 1,066 | 958 |
| **Total other noncurrent assets** | **11,267** | **10,592** |
| **TOTAL ASSETS** | **$ 66,417** | **$ 63,037** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED BALANCE SHEETS**

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions, except share amounts) | September 30, 2016 | December 31, 2015 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 981 | $ 1,019 |
| Long-term debt, classified as current | 160 | 160 |
| Accounts payable: | | |
| Trade creditors | 1,370 | 1,414 |
| Regulatory balancing accounts | 764 | 715 |
| Other | 765 | 418 |
| Disputed claims and customer refunds | 233 | 454 |
| Interest payable | 144 | 203 |
| Other | 1,681 | 1,750 |
| **Total current liabilities** | **6,098** | **6,133** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 16,179 | 15,577 |
| Regulatory liabilities | 6,613 | 6,321 |
| Pension and other postretirement benefits | 2,540 | 2,534 |
| Asset retirement obligations | 4,672 | 3,643 |
| Deferred income taxes | 10,135 | 9,487 |
| Other | 2,350 | 2,282 |
| **Total noncurrent liabilities** | **42,489** | **39,844** |
| **Commitments and Contingencies (Note 9)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 7,955 | 7,215 |
| Reinvested earnings | 8,291 | 8,262 |
| Accumulated other comprehensive income | 4 | 3 |
| **Total shareholders' equity** | **17,830** | **17,060** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 66,417** | **$ 63,037** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | (Unaudited) | |
|---|---|---|
| | Nine Months Ended September 30, | |
| **(in millions)** | **2016** | **2015** |
| **Cash Flows from Operating Activities** | | |
| Net income | $ 706 | $ 715 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 2,090 | 1,935 |
| Allowance for equity funds used during construction | (84) | (80) |
| Deferred income taxes and tax credits, net | 648 | 245 |
| Disallowed capital expenditures | 517 | 270 |
| Other | 234 | 200 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | (546) | (321) |
| Inventories | (38) | 5 |
| Accounts payable | 194 | 148 |
| Income taxes receivable/payable | (64) | 14 |
| Other current assets and liabilities | 258 | (45) |
| Regulatory assets, liabilities, and balancing accounts, net | (634) | 78 |
| Other noncurrent assets and liabilities | (75) | (232) |
| **Net cash provided by operating activities** | **3,206** | **2,932** |
| **Cash Flows from Investing Activities** | | |
| Capital expenditures | (4,128) | (3,662) |
| Decrease in restricted cash | 66 | 11 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,019 | 1,023 |
| Purchases of nuclear decommissioning trust investments | (1,050) | (1,124) |
| Other | 10 | 18 |
| **Net cash used in investing activities** | **(4,083)** | **(3,734)** |
| **Cash Flows from Financing Activities** | | |
| Net issuances (repayments) of commercial paper, net of discount of $5 and $2 at respective dates | (293) | 545 |
| Short-term debt financing | 250 | - |
| Short-term debt matured | - | (300) |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 and $14 at respective dates | 594 | 486 |
| Preferred stock dividends paid | (10) | (10) |
| Common stock dividends paid | (423) | (537) |
| Equity contribution from PG&E Corporation | 740 | 605 |
| Other | 28 | 20 |
| **Net cash provided by financing activities** | **886** | **809** |
| **Net change in cash and cash equivalents** | 9 | 7 |
| **Cash and cash equivalents at January 1** | 59 | 55 |
| **Cash and cash equivalents at September 30** | **$ 68** | **$ 62** |

| | | | | |
|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | |
| Cash received (paid) for: | | | | |
| Interest, net of amounts capitalized | $ | (602) | $ | (561) |
| Income taxes, net | | 151 | | - |
| **Supplemental disclosures of noncash investing and financing activities** | | | | |
| Common stock dividends declared but not yet paid | $ | 244 | $ | - |
| Capital expenditures financed through accounts payable | | 325 | | 245 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

## NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

### NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility operate in one segment, as the companies assess financial performance and allocate resources on a consolidated basis.

The accompanying Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of PG&E Corporation and the Utility's financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 2015 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2015 Form 10-K. This quarterly report should be read in conjunction with the 2015 Form 10-K.

The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred.

### NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Note 2 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility has a controlling interest or was the primary beneficiary of any of these VIEs at September 30, 2016, the Utility assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at September 30, 2016, it did not consolidate any of them.

**Asset Retirement Obligations**

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three yearsin conjunction with the Nuclear Decommissioning Cost Triennial Proceedings. In the first quarter of 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC, which reflects an increase of approximately $1.4 billion in the estimated undiscounted cost to decommission the Utility's nuclear power plants. The change in total estimated cost resulted in an $818 million adjustment to the ARO recognized on the Condensed Consolidated Balance Sheets. The adjustment relates to spent fuel storage, staffing, and out-of-state waste disposal costs. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

On June 20, 2016, the Utility entered into a joint proposalwith certain parties to retire Diablo Canyon nuclear power plant at the expiration of its current operating licenses in 2024 (Unit 1) and 2025 (Unit 2), subject to certain approvals, resulting in an additional $115 million increase to the ARO recognized on the Condensed Consolidated Balance Sheets in the second quarter of 2016.

The estimated total nuclear decommissioning cost of $4.8 billion is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.5 billion at September 30,2016 and $2.5 billion at December 31, 2015. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

**Pension and Other Postretirement Benefits**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan and cash balance plan. Both plans are included in "Pension Benefits" below. Post-retirement medical and life insurance plans are included in "Other Benefits" below.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2016 and 2015 were as follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | | |
| **(in millions)** | **2016** | **2015** | **2016** | **2015** |
| Service cost for benefits earned | $ 113 | $ 123 | $ 13 | $ 14 |
| Interest cost | 179 | 168 | 19 | 18 |
| Expected return on plan assets | (207) | (219) | (26) | (28) |
| Amortization of prior service cost | 2 | 4 | 3 | 4 |
| Amortization of net actuarial loss | 6 | 1 | 1 | 1 |
| **Net periodic benefit cost** | **93** | **77** | **10** | **9** |
| Regulatory account transfer [1] | (8) | 8 | - | - |
| **Total** | **$ 85** | **$ 85** | **$ 10** | **$ 9** |

[1] The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates.

| (in millions) | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | Nine Months Ended September 30, | | | |
| | 2016 | 2015 | 2016 | 2015 |
| Service cost for benefits earned | $ 339 | $ 360 | $ 39 | $ 41 |
| Interest cost | 537 | 505 | 57 | 54 |
| Expected return on plan assets | (621) | (655) | (80) | (84) |
| Amortization of prior service cost | 6 | 11 | 11 | 14 |
| Amortization of net actuarial loss | 18 | 7 | 3 | 3 |
| **Net periodic benefit cost** | **279** | **228** | **30** | **28** |
| Regulatory account transfer [1] | (25) | 26 | - | - |
| **Total** | **$ 254** | **$ 254** | **$ 30** | **$ 28** |

[1] The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (Loss)**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) are summarized below:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| | Three Months Ended September 30, 2016 | | |
| Beginning balance | $ (23) | $ 16 | $ (7) |
| **Amounts reclassified from other comprehensive income:** [1] | | | |
| Amortization of prior service cost (net of taxes of $0 and $2, respectively) | 2 | 1 | 3 |
| Amortization of net actuarial loss (net of taxes of $3 and $0, respectively) | 3 | 1 | 4 |
| Regulatory account transfer (net of taxes of $3 and $2, respectively) | (5) | (2) | (7) |
| **Net current period other comprehensive gain (loss)** | - | - | - |
| **Ending balance** | **$ (23)** | **$ 16** | **$ (7)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| | Three Months Ended September 30, 2015 | | |
| Beginning balance | $ (21) | $ 15 | $ (6) |
| **Amounts reclassified from other comprehensive income:** [1] | | | |
| Amortization of prior service cost (net of taxes of $1 and $2, respectively) | 3 | 2 | 5 |
| Amortization of net actuarial loss (net of taxes of $0, and $0, respectively) | 1 | 1 | 2 |
| Regulatory account transfer (net of taxes of $3 and $3, respectively) | (4) | (3) | (7) |
| **Net current period other comprehensive gain (loss)** | - | - | - |
| **Ending balance** | **$ (21)** | **$ 15** | **$ (6)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| | Nine Months Ended September 30, 2016 | | |
| Beginning balance | $ (23) | $ 16 | $ (7) |
| **Amounts reclassified from other comprehensive income:** [1] | | | |
| Amortization of prior service cost (net of taxes of $2 and $5, respectively) | 4 | 6 | 10 |
| Amortization of net actuarial loss (net of taxes of $7 and $1, respectively) | 11 | 2 | 13 |
| Regulatory account transfer (net of taxes of $9 and $6, respectively) | (15) | (8) | (23) |
| **Net current period other comprehensive gain (loss)** | - | - | - |
| **Ending balance** | **$ (23)** | **$ 16** | **$ (7)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Other Investments | Total |
|---|---|---|---|---|
| | Nine Months Ended September 30, 2015 | | | |
| Beginning balance | $ (21) | $ 15 | $ 17 | $ 11 |
| **Amounts reclassified from other comprehensive income:** | | | | |
| Amortization of prior service cost (net of taxes of $4, $6, and $0, respectively) [(1)] | 7 | &bbsp; 8 | - | 15 |
| Amortization of net actuarial loss (net of taxes of $3, $1, and $0, respectively) [(1)] | 4 | 2 | - | 6 |
| Regulatory account transfer (net of taxes of $7, $7, and $0, respectively) [(1)] | (11) | (10) | - | (21) |
| Change in investments (net of taxes of $0, $0, and $12, respectively) | - | - | (17) | (17) |
| **Net current period other comprehensive gain (loss)** | **-** | **-** | **(17)** | **(17)** |
| **Ending balance** | **$ (21)** | **$ 15** | **$ -** | **$ (6)** |

[(1)] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above, with the exception of other investments which are held by PG&E Corporation.

**Recently Adopted Accounting Guidance**

***Fair Value Measurement***

In May 2015, the FASB issued ASU No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which standardizes reporting practices related to the fair value hierarchy for all investments for which fair value is measured using the net asset value per share. PG&E Corporation and the Utility adopted this guidance effectiveJanuary 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this standard did not impact their Condensed Consolidated Financial Statements. All prior periods presented in these Condensed Consolidated financial statements reflect the retrospective adoption of this guidance. (See Note 8 below.)

***Accounting for Fees Paid in a Cloud Computing Arrangement***

In April 2015, the FASB issued ASU No. 2015-05, Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement, which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this guidance did not have a material impact on their Condensed Consolidated Financial Statements.

***Presentation of Debt Issuance Costs***

In April 2015, the FASB issued ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,* which amends the existing guidance relating to the presentation of debt issuance costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this guidance did not have a material impact on their Condensed Consolidated Financial Statements. PG&E Corporation and the Utility reclassified $105 million and $103 million, respectively, of debt issuance costs as of December 31, 2015 with no impact to net income or total shareholders' equity previously reported. All prior periods presented in these Condensed Consolidated Financial Statements reflect the retrospective adoption of this guidance.

**Accounting Standards Issued But Not Yet Adopted**

***Share-based Payment Accounting***

In March 2016, the FASB issued ASU No. 2016-09, *Compensation - Stock Compensation (Topic 718),* which amends the existing guidance relating to the accounting for share-based payment awards issued to employees, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2017. PG&E Corporation and the Utility will early adopt this guidance in the fourth quarter of 2016 and do not expect this ASU to have a material impact on their Condensed Consolidated Financial Statements and related disclosures.

***Recognition of Lease Assets and Liabilities***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842),* which amends the existing guidance relating to the recognition of lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019 with retrospective application. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

***Recognition and Measurement of Financial Assets and Financial Liabilities***

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*, which amends the existing guidance relating to the recognition and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

***Revenue Recognition Standard***

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which amends the existing revenue recognition guidance. In August 2015, the FASB deferred the effective date of this amendment for public companies by one year to January 1, 2018, with early adoption permitted as of the original effective date of January 1, 2017. (See ASU No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*.) PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

**NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS**

**Regulatory Assets**

Long-term regulatory assets are composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **September 30, 2016** | **December 31, 2015** |
| Pension benefits | $ 2,416 | $ 2,414 |
| Deferred income taxes | 3,649 | 3,054 |
| Utility retained generation | 376 | 411 |
| Environmental compliance costs | 760 | 748 |
| Price risk management | 96 | 138 |
| Unamortized loss, net of gain, on reacquired debt | 81 | 94 |
| Other | 156 | 170 |
| **Total long-term regulatory assets** | **$ 7,534** | **$ 7,029** |

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

**Regulatory Liabilities**

Long-term regulatory liabilities are composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **September 30, 2016** | **December 31, 2015** |
| Cost of removal obligations | $ 4,939 | $ 4,605 |
| Recoveries in excess of asset retirement obligations | 656 | 631 |
| Public purpose programs | 539 | 600 |
| Other | 479 | 485 |
| **Total long-term regulatory liabilities** | **$ 6,613** | **$ 6,321** |

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

**Regulatory Balancing Accounts**

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets - regulatory assets or noncurrent liabilities - regulatory liabilities, respectively, in the Condensed Consolidated Balance Sheets. These differences do not have an impact on net income. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

| | Receivable Balance at | |
|---|---|---|
| **(in millions)** | **September 30, 2016** | **December 31, 2015** |
| Electric distribution | $ 43 | $ 380 |
| Utility generation | - | 122 |
| Gas distribution | 583 | 493 |
| Energy procurement | 174 | 262 |
| Public purpose programs | 122 | 155 |
| Other | 553 | 348 |
| **Total regulatory balancing accounts receivable** | **$ 1,475** | **$ 1,760** |

| | Payable Balance at | |
|---|---|---|
| **(in millions)** | **September 30, 2016** | **December 31, 2015** |
| Utility generation | $ 47 | $ - |
| Energy procurement | 109&bbsp; | 112 |
| Public purpose programs | 289 | 244 |
| Other | 319 | 359 |
| **Total regulatory balancing accounts payable** | **$ 764** | **$ 715** |

The electric distribution, utility generation, and gas distribution balancing accounts track the collection of revenue requirements approved in the GRC. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency and low income energy efficiency.

**NOTE 4: DEBT**

**Revolving Credit Facilities and Commercial Paper Program**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at September 30, 2016:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2021 | $ 300 (1) | $ - | $ 165 | $ 135 |
| Utility | April 2021 | 3,000 (2) | 31 | 731 | 2,238 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 31** | **$ 896** | **$ 2,373** |

(1) Includes a $50 million lender commitment to the letter of credit sublimit and a $100 million commitment for "swingline" loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.

(2) Includes a $500 million lender commitment to the letter of credit sublimit and a $75 million commitment for swingline loans.

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021.

**Other Short-term Borrowings**

In March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

**Senior Notes Issuances**

In March 2016, the Utility issued $600 million principal amount of 2.95% Senior Notes due March 1, 2026. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

**Variable Rate Interest**

AtSeptember 30, 2016, the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.89% to 0.92%. At September 30, 2016, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.77% to 0.85%. Pollution control bonds Series 2009 C and D will mature on December 1, 2016.

## NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the nine months ended September 30, 2016were as follows:

| | PG&E Corporation | Utility |
|---|---|---|
| (in millions) | Total Equity | Total Shareholders' Equity |
| **Balance at December 31, 2015** | **$ 16,828** | **$ 17,060** |
| Comprehensive income | 711 | 707 |
| Equity contributions | - | 740 |
| Common stock issued | 742 | - |
| Share-based compensation | 59 | - |
| Common stock dividends declared | (724) | (667) |
| Preferred stock dividend requirement | - | (10) |
| Preferred stock dividend requirement of subsidiary | (10) | - |
| **Balance at September 30, 2016** | **$ 17,606** | **$ 17,830** |

During the three and nine months ended September 30, 2016, PG&E Corporation sold 0.4 million and 2.6 million shares of its common stock under the February 2015 equity distribution agreement for cash proceeds of $26 million and $149 million, respectively, net of commissions paid of $0.2 million and $1.3 million, respectively. As of September 30, 2016, the remaining gross sales available under this agreement were $275 million.

In August 2016, PG&E Corporation sold 4.9 million shares of its common stock in an underwritten public offering for net cash proceeds of $309 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the nine months ended September 30, 2016, 5.7 million shares were issued for cash proceeds of $269 million under these plans.

## NOTE 6: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in millions, except per share amounts) | 2016 | 2015 | 2016 | 2015 |
| **Income available for common shareholders** | $ 388 | $ 307 | $ 701 | $ 740 |
| **Weighted average common shares outstanding, basic** | 501 | 486 | 497 | 481 |
| Add incremental shares from assumed conversions: | | | | |
| Employee share-based compensation | 2 | 3 | 3 | 3 |
| **Weighted average common shares outstanding, diluted** | 503 | 489 | 500 | 484 |
| **Total earnings per common share, diluted** | **$ 0.77** | **$ 0.63** | **$ 1.40** | **$ 1.53** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

## NOTE 7: DERIVATIVES

### Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Derivatives are recorded at fair value and are presented in the Utility'sCondensed Consolidated Balance Sheets on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives as long as the current ratemaking mechanism remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Condensed Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

**Volume of Derivative Activity**

The volumes of the Utility's outstanding derivatives were as follows:

| | | Contract Volume at | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **September 30, 2016** | **December 31, 2015** |
| Natural Gas [(1)] (MMBtus [(2)]) | Forwards, Futures and Swaps | 376,296,893 | 333,091,813 |
| | Options | 118,017,176 | 111,550,004 |
| Electricity (Megawatt-hours) | Forwards, Futures and Swaps | 3,128,038 | 3,663,512 |
| | Congestion Revenue Rights [(3)] | 172,756,395 | 216,383,389 |

[(1)]Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.
[(2)] Million British Thermal Units.
[(3)] CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

**Presentation of Derivative Instruments in the Financial Statements**

At September 30, 2016, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets - other | $ 100 | $ (8) | $ 14 | $ 106 |
| Other noncurrent assets - other | 128 | (8) | - | 120 |
| Current liabilities - other | (67) | 8 | 10 | (49) |
| Noncurrent liabilities - other | (104) | 8 | 7 | (89) |
| **Net commodity risk** | **$ 57** | **$ -** | **$ 31** | **$ 88** |

At December 31, 2015, the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| Current assets - other | $ 97 | $ (4) | $ 25 | $ 118 |
| Other noncurrent assets - other | 172 | (2) | - | 170 |
| Current liabilities - other | (102) | 4 | 44 | (54) |
| Noncurrent liabilities - other | (140) | 2 | 21 | (117) |
| **Net commodity risk** | **$ 27** | **$ -** | **$ 90** | **$ 117** |

Gains and losses associated with price risk management activities were recorded as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| **(in millions)** | 2016 | 2015 | 2016 | 2015 |
| Unrealized gain (loss) - regulatory assets and liabilities (1) | $ (29) | $ (45) | $ 30 | $ (69) |
| Realized gain (loss) - cost of electricity (2) | (7) | 1 | (48) | 4 |
| Realized loss - cost of natural gas (2) | (9) | (3) | (15) | (8) |
| **Net commodity risk** | **$ (45)** | **$ (47)** | **$ (33)** | **$ (73)** |

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Condensed Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Condensed Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At September 30, 2016, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

| | Balance at | |
|---|---|---|
| **(in millions)** | September 30, 2016 | December 31, 2015 |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (8) | $ (2) |
| Related derivatives in an asset position | 4 | - |
| Collateral posting in the normal course of business related to these derivatives | 2 | - |
| **Net position of derivative contracts/additional collateral posting requirements (1)** | **$ (2)** | **$ (2)** |

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

## NOTE 8: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 -** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 -** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 -** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At September 30, 2016 | | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Netting [1]** | **Total** |
| **Assets:** | | | | | |
| Short-term investments | $ - | $ - | $ - | $ - | $ - |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 1 | - | - | - | **1** |
| Global equity securities | 1,678 | - | - | - | **1,678** |
| Fixed-income securities | 720 | 530 | - | - | **1,250** |
| Assets measured at NAV | - | - | - | - | **14** |
| **Total nuclear decommissioning trusts [2]** | **2,399** | **530** | **-** | **-** | **2,943** |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | 10 | 16 | 192 | (2) | **216** |
| Gas | - | 10 | - | - | **10** |
| **Total price risk management instruments** | **10** | **26** | **192** | **(2)** | **226** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 59 | - | - | **59** |
| Life insurance contracts | - | 77 | - | - | **77** |
| **Total rabbi trusts** | **-** | **136** | **-** | **-** | **136** |
| Long-term disability trust | | | | | |
| Short-term investments | 4 | - | - | - | **4** |
| Assets measured at NAV | - | - | - | - | **138** |
| **Total long-term disability trust** | **4** | **-** | **-** | **-** | **142** |
| **Total assets** | **$ 2,413** | **$ 692** | **$ 192** | **$ (2)** | **$ 3,447** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | $ 25 | $ 8 | $ 136 | $ (33) | $ **136** |
| Gas | - | 2 | - | - | **2** |
| **Total liabilities** | **$ 25** | **$ 10** | **$ 136** | **$ (33)** | **$ 138** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $346 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements At December 31, 2015 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Short-term investments | $ 64 | $ - | $ - | $ - | $ **64** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 36 | - | - | - | **36** |
| Global equity securities | 1,520 | - | - | - | **1,520** |
| Fixed-income securities | 694 | 521 | - | - | **1,215** |
| Assets measured at NAV | - | - | - | - | **13** |
| **Total nuclear decommissioning trusts [2]** | **2,250** | **521** | **-** | **-** | **2,784** |
| Price risk management instruments (Note 9 in the 2015 Form 10-K) | | | | | |
| Electricity | - | 9 | 259 | 18 | **286** |
| Gas | - | 1 | - | 1 | **2** |
| **Total price risk management instruments** | **-** | **10** | **259** | **19** | **288** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 57 | - | - | **57** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **127** | **-** | **-** | **127** |
| Long-term disability trust | | | | | |
| Short-term investments | 7 | - | - | - | **7** |
| Assets measured at NAV | - | - | - | - | **158** |
| **Total long-term disability trust** | **7** | **-** | **-** | **-** | **165** |
| **Total assets** | **$ 2,321** | **$ 658** | **$ 259** | **$ 19** | **$ 3,428** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9 in the 2015 Form 10-K) | | | | | |
| Electricity | $ 69 | $ 1 | $ 170 | $ (70) | $ **170** |
| Gas | - | 2 | - | (1) | **1** |
| **Total liabilities** | **$ 69** | **$ 3** | **$ 170** | **$ (71)** | **$ 171** |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $314 million, primarily related to deferred taxes on appreciation of investment value.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the nine months ended September 30, 2016 and 2015.

***Trust Assets***

*Assets Measured at Fair Value*

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

*Assets Measured at NAV Using Practical Expedient*

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*and applied it retrospectively for the periods presented in their Condensed Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Condensed Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

***Price Risk Management Instruments***

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk management function, which reports to the Chief Risk and Audit Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 7 above.)

| (in millions) | Fair Value at At September 30, 2016 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [(1)] |
| Congestion revenue rights | $ 192 | $ 43 | Market approach | CRR auction prices | $ (23.81) - 8.76 |
| Power purchase agreements | $ - | $ 93 | Discounted cash flow | Forward prices | $ 18.07 - 38.80 |

(1) Represents price per megawatt-hour

| (in millions) | Fair Value at At December 31, 2015 | | Valuation | Unobservable | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Technique | Input | Range [(1)] |
| Congestion revenue rights | $ 259 | $ 63 | Market approach | CRR auction prices | $ (161.36) - 8.76 |
| Power purchase agreements | $ - | $ 107 | Discounted cash flow | Forward prices | $ 15.08 - 37.27 |

(1) Represents price per megawatt-hour

**Level 3 Reconciliation**

The following tables present the reconciliation for Level 3 price risk management instruments for the three and nine months ended September 30, 2016 and 2015:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Asset (liability) balance as of July 1 | **$ 66** | **$ 48** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [(1)] | (10) | (27) |
| **Asset (liability) balance as of September 30** | **$ 56** | **$ 21** |

(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Asset (liability) balance as of January 1 | **$ 89** | **$ 69** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [(1)] | (33) | (48) |
| **Asset (liability) balance as of September 30** | **$ 56** | **$ 21** |

(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

**Financial Instruments**

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at September 30, 2016 and December 31, 2015, as they are short-term in nature or have interest rates that reset daily.
- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at September 30, 2016 and December 31, 2015.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

| | At September 30, 2016 | | At December 31, 2015 | |
|---|---|---|---|---|
| (in millions) | Carrying Amount | Level 2 Fair Value | Carrying Amount | Level 2 Fair Value |
| PG&E Corporation | $ 350 | $ 356 | $ 350 | $ 354 |
| Utility | 15,417 | 18,440 | 14,918 | 16,422 |

***Available for Sale Investments***

The following table provides a summary of available-for-sale investments:

| (in millions) | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| **As of September 30, 2016** | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 1 | $ - | $ - | $ 1 |
| Global equity securities | 579 | 1,116 | (3) | 1,692 |
| Fixed-income securities | 1,164 | 89 | (3) | 1,250 |
| **Total** [1] | **$ 1,744** | **$ 1,205** | **$ (6)** | **$ 2,943** |
| **As of December 31, 2015** | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 36 | $ - | $ - | $ 36 |
| Global equity securities | 508 | 1,034 | (9) | 1,533 |
| Fixed-income securities | 1,165 | 58 | (8) | 1,215 |
| **Total** [1] | **$ 1,709** | **$ 1,092** | **$ (17)** | **$ 2,784** |

(1) Represents amounts before deducting $346 million and $314 million at September 30, 2016 and December 31, 2015, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

| (in millions) | As of September 30, 2016 |
|---|---|
| Less than 1 year | $ 33 |
| 1-5 years | 443 |
| 5-10 years | 271 |
| More than 10 years | 503 |
| **Total maturities of fixed-income securities** | **$ 1,250** |

The following table provides a summary of activity for the investments:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in millions) | 2016 | 2015 | 2016 | 2015 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $ 257 | $ 244 | $ 1,019 | $ 1,023 |
| Gross realized gains on securities held as available-for-sale | 6 | 3 | 15 | 50 |
| Gross realized losses on securities held as available-for-sale | (14) | (12) | (17) | (25) |

## NOTE 9: CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows may be materially affected by the outcome of the following matters.

### Enforcement and Litigation Matters

#### *CPUC Matters*

*Order Instituting an Investigation into Compliance with Ex Parte Communication Rules*

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have occurred or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker or a commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices.

On July 12, 2016, the assigned commissioner and ALJ issued a ruling that adopted recommendations included in a process report jointly submitted by the Cities of San Bruno and San Carlos, ORA, the SED, TURN (together, the "other parties"), and the Utility in April 2016. The approved framework for resolving the proceeding included a total of 159 communications (the 46 communications already included in the OII and 113 additional communications) in the scope of the proceeding, a procedure for moving undisputed facts into the evidentiary record and a diligence process for providing additional factual information. The Utility and the other parties disagreed on the inclusion of an additional 21 communications in the scope and filed briefs on the issue. The ruling confirmed that these additional 21 communications were not included within the scope of the OII and do not, in themselves, appear to be ex parte violations, but granted the other parties' request to seek additional information regarding these communications.

In a status report jointly submitted to the CPUC on October 14, 2016, the parties proposed an update to the framework for resolving the proceeding. The revised framework includes a total of 165 communications (159 communications previously included in the proceeding, reduced by two communications the other parties agreed not to pursue, plus 8 additional communications out of 21 communications previously in disagreement). The parties also proposed to begin settlement discussions on November 30, 2016, followed by a joint status report proposed for January 13, 2017. In the event a settlement cannot be reached, the parties proposed to submit their opening briefs on January 27, 2017, and reply briefs on February 17, 2017. On October 31, 2016, the CPUC issued a proposed decision adopting the schedule proposed by the parties in the October 14, 2016 status report. The proposed decision extends the statutory deadline for this proceeding to May 17, 2017 in order to allow the parties to complete settlement discussions or file briefs, and for the ALJ to prepare and file a proposed decision.

The Utility expects that the other parties may argue that the number of violations exceeds the 165 communications referenced in the October 14, 2016 joint status report either because a single communication may have violated more than one rule or because they believe some of the material provided during discovery constitutes impermissible ex parte communications. The Utility expects to contest many of these assertions. If the matter does not settle, the CPUC will determine which communications included within the scope of the proceeding were in violation of its rules. The CPUC will also determine whether to impose penalties or other remedies, as a result of a potential settlement or otherwise. The CPUC can impose fines up to $50,000 for each violation, and up to $50,000 per day if the CPUC determines that the violation was continuing. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII but are unable to reasonably estimate the amount or range of future charges that could be incurred, because it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office also have been investigating matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility is cooperating with these investigations. It is uncertain whether any charges will be brought against the Utility.

*CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping*

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices with respect to maintaining safe operation of its natural gas distribution service and facilities. The order also required the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cited the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014.

On August 18, 2016, the CPUC unanimously approved a modified presiding officer's decision (the "MOD POD") issued on August 17, 2016 in this investigation. In accordance with the MOD POD, the amount of the fine increased from $24.3 million to $25.6 million, to include a $50,000 fine omitted from the June 1, 2016 presiding officer's decision (the "POD") and $1.3 million resulting from the per-day fine increase for the missing leak repair records for the De Anza division. With the $10.85 million citation previously paid in 2015 for the City of Carmel-by-the-Sea ("Carmel") incident, the total fine imposed on the Utility was $36.5 million. The remaining $25.6 million was paid in September 2016.

In accordance with the MOD POD, the decision denies the appeals previously filed by the SED and Carmel from the POD, and closes this proceeding but allows the parties an opportunity to request that this proceeding be reopened if needed to ensure proper implementation of a compliance plan to be developed by the parties.

On September 26, 2016, the SED filed an application for rehearing of the CPUC's decision. Specifically, the application indicates that the CPUC erred in certain of its determinations (including those related to maximum allowable operating pressure documentation that, if adopted, could result in an additional fine of $7 million), calculations (including thoserelated to the missing DeAnza records violations) and certain other findings, and requests that the CPUC adopt its recommendations. On October 11, 2016, the Utility submitted its response to the CPUC in which it opposed the SED's application for rehearing arguing that the application failed to identify a legal error warranting rehearing by the CPUC. The Utility cannot predict when or if the CPUC will grant the rehearing or if it will adopt the SED's recommendations.

On October 24, 2016, the Utility held a meet and confer with parties to develop remedial measures necessary to address the issues identified in the CPUC decision with the objective of establishing a compliance plan that includes all feasible and cost-effective measures necessary to improve the Utility's natural gas distribution system record-keeping. Under the current schedule, the parties are expected to submit a compliance plan to the CPUC on or before December 16, 2016.

*Natural Gas Transmission Pipeline Rights-of-Way*

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

*Potential Safety Citations*

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose fines for violations identified through audits, investigations, or self-reports. The SED can impose fines up to $50,000 for each violation, per day, and can consider the discretionary factors discussed above (see "Order Instituting an Investigation into Compliance with Ex Parte Communication Rules" above) in determining the number of violations and whether to impose daily fines for continuing violations. On September 29, 2016, the CPUC issued a final decision adopting improvements and refinements to its gas and electric safety citation programs. Specifically, the final decision refines the criteria for the SED to use in determining whether to issue a citation and the amount of penalty, sets an administrative limit of $8 million per citation issued, makes self-reporting voluntary in both gas and electric programs, adopts detailed criteria for the utilities to use to voluntarily self-report a potential violation, and refines other issues in the programs. The decision also merges the rules applicable to its gas and electric safety citation programs into a single set of rules that replace the previous safety citation programs and adopts non-substantive changes to these programs so that the programs can be similar in structure and process where appropriate. The decision closes the proceeding.

The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The Utility believes it is probable that the SED will impose fines or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

In September 2016, the Utility reported that it discovered in November 2015 that approximately 550,000 atmospheric corrosion inspections on above-ground gas distribution meters completed in 2014, which constituted 35% of such inspections in 2014, were performed by non-operator qualified personnel. The Utility did not provide timely notification of such non-compliance to the CPUC. The SED is investigating the Utility's self-report.

The SED could impose fines on the Utility of up to $50,000 per inspection, and also for failure to timely file a self-report in connection with such inspections. The SED has the authority to issue more than one citation for a series of related incidents, and the CPUC can issue an OII and possible additional fines even after the SED has issued a citation. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines that could be imposed with respect to this self-report, for the reasons indicated above, or to predict whether the CPUC will open a formal proceeding as a result of the SED's investigation.

***Federal Matters***

*Federal Criminal Trial*

On June 14, 2016, a federal criminal trial against the Utilitybegan in the United States District Court for the Northern District of California, in San Francisco, on 12 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility illegally obstructed the NTSB investigation into the cause of the San Bruno accident. On July 26, 2016, the court granted the government's motion to dismiss Count 13 alleging that the Utility knowingly and willfully failed to retain a strength test pressure record with respect to a distribution feeder main, thereby reducing the total number of counts from 13 to 12.

On August 2, 2016, the remaining Alternative Fines Act sentencing allegations in the case were dismissed. The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." (The remaining allegations related to $281 million of gross gains that the government alleged the Utility derived. As previously disclosed, in December 2015, the court dismissed the government's allegations regarding the amount of losses.)

On August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act.

On August 16, 2016, the Utility filed a motion under Federal Rule of Criminal Procedure 29 for a judgment of acquittal, arguing that the evidence was insufficient to sustain a conviction for the six counts on which the jury returned a guilty verdict. The court indicated that it will decide on this motion based on briefs filed by the parties, without oral argument. The Utility is not able to predict when the court will decide on the motion. A sentencing hearing is currently scheduled for January 23, 2017.

The maximum statutory fine for each felony count is $500,000, for total potential maximum statutory fines of $3 million. At September 30, 2016, the Utility's Condensed Consolidated Balance Sheets include a $3 million accrual in connection with the jury verdict. The Utility also could incur material costs, not recoverable through rates, to implement remedial and other measures that could be imposed, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by an independent third-party monitor. If appointed, the Utility expects a monitor would serve for a period of time and report periodically to the court or a department or agency of the government.

*Other Federal Matters*

In July 2014, the Utility was informed that the U.S. Attorney's Office is investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the criminal trial discussed above. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The investigation involves a removal by the Utility of a hazardous tree that contained an osprey nest and egg in Inverness, California, on March 18, 2016. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

***Other Litigation Matters***

*Butte Fire Litigation*

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, and destroyed 549 homes, 368 outbuildings and four commercial properties. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of September 30, 2016, approximately 50 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,850 individual plaintiffs representing approximately 800 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling preference cases (presented by individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling). The Utility also has begun scheduling mediation of other cases. Case management conferences were held on July 14, 2016 and September 1, 2016. The next case management conference is scheduled for December 1, 2016.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes it was not negligent; however, there can be no assurance that a court or jury would agree with the Utility.

Based on the evidence described in the Cal Fire report that the Gray Pine tree contacted an electric line of the Utility, the Utility believes that it is probable that it will incur a loss of $350 million for property damages (including estimated damages to structures and their contents, and to trees) in connection with this matter, which corresponds to the lower end of the range of its reasonably estimable losses. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the extent of damage to such structures and contents, and other property damage. The estimate does not include fire suppression costs, personal injury damages and other damages that the Utility could be liable for if it were found to have been negligent.

The Utility believes that it is reasonably possible that it will incur losses related to Butte fire claims in excess of the $350 million accrued through September 30, 2016. The Utility believes that $90 million is a reasonable estimate of fire suppression costs (this amount is not included in the $350 million accrued through September 30, 2016). The Utility currently is unable to reasonably estimate the upper end of the range because it is still at an early stage of the evaluation of claims, the mediation and settlement process, and discovery.

The process for estimating costs associated with claims relating to the Butte fire, including for estimated property damages, requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including discovery from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may change, including management's ability to reasonably estimate a range of loss.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. In the second quarter of 2016, the Utility recorded $260 million for probable insurance recoveries in connection with recovery of losses related to the Butte fire, included in Other accounts receivable in the Condensed Consolidated Balance Sheets. The Utility plans to seek recovery of all insured losses, and while the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses) relating to Butte fire will ultimately be recovered through its insurance, it is unable to predict the amount and timing of such insurance recoveries.

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals during such reporting periods.

*Other Contingencies*

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $84 million at September 30, 2016 and $63 million at December 31, 2015. These amounts are included in Other current liabilities in the Condensed Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowances are reflected in operating and maintenance expenses in the Condensed Consolidated Statements of Income. Disallowances as a result of the CPUC's June 23, 2016 final phase one decision in the Utility's 2015 GT&S rate case, the April 9, 2015 Penalty Decision and the Utility's Pipeline Safety Enhancement Plan are discussed below.

*2015 GT&S Rate Case Disallowance of Capital Expenditures*

On June 23, 2016, the CPUC approved a final decision in phase one of the Utility's 2015 GT&S rate case. The decision permanently disallowed a portion of the 2011 through 2014 capital spending in excess of the amount adopted and established various cost caps that will increase the risk of overspend over the current rate case cycle, including new one-way capital balancing accounts. As a result, in the second quarter of 2016, the Utility incurred charges of $190 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This included $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the third party audit of 2011 through 2014 capital spending.

*Penalty Decision's Disallowance of Natural Gas Capital Expenditures*

On April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings pending against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "Penalty Decision"). In January 2016, the CPUC closed the investigative proceedings. The total penalty includes (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million.

On November 1, 2016, the assigned ALJ issued a phase two proposed decision in the Utility's 2015 GT&S rate case, which applies $689 million of the $850 million penalty to capital expenditures. The decision also approves the Utility's list of programs and projects that meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty. The Utility expects a final CPUC decision to be voted in December 2016.

For the three and nine months ended September 30, 2016, the Utility recorded charges for disallowed capital spending of $51 million and $286 million, respectively, as a result of the Penalty Decision. The cumulative charges at September 30, 2016, and the additional future charges to reach the $1.6 billion total are shown in the following table:

| (in millions) | Nine Months Ended September 30, 2016 | Cumulative Charges September 30, 2016 | Future Charges and Costs | Total Amount |
|---|---|---|---|---|
| Fine paid to the state | $ - | $ 300 | $ - | $ 300 |
| Customer bill credit paid | - | 400 | - | 400 |
| Charge for disallowed capital [1] | 286 | 692 | - | 692 |
| Disallowed revenue for pipeline safety expenses [2] | 8 | 8 | 150 | 158 |
| CPUC estimated cost of other remedies [3] | - | - | - | 50 |
| **Total Penalty Decision fines and remedies** | **$ 294** | **$ 1,400** | **$ 150** | **$ 1,600** |

[1] The Penalty Decision disallows the Utility from recovering $850 million in costs associated with pipeline safety-related projects and programs that the CPUC will finalize in a final phase two decision to be issued in the Utility's 2015 GT&S rate case. The CPUC recommended in its May 5, 2016 phase one proposed decision in the Utility's 2015 GT&S rate case that at least $692 million of the $850 million cost disallowance be allocated to capital expenditures. On November 1, 2016, the CPUC issued a phase two proposed decision in the 2015 GT&S rate case which allocates $689 million to capital expenditures.

[2] Future GT&S revenues will be reduced for these unrecovered expenses.

[3] In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision. This table does not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. These costs would be expensed as incurred.

*Capital Expenditures Relating to Pipeline Safety Enhancement Plan*

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of September 30, 2016, the Utility has spent $1.3 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected to exceed the authorized amount. The Utility expects the remaining PSEP work to continue beyond 2016. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

**Environmental Remediation Contingencies**

The Utility's environmental remediation liability is primarily included in non-current liabilities on the Condensed Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| (in millions) | September 30, 2016 | December 31, 2015 |
| Topock natural gas compressor station [1] | $ 300 | $ 300 |
| Hinkley natural gas compressor station [1] | 140 | 140 |
| Former manufactured gas plant sites owned by the Utility or third parties | 305 | 271 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites | 143 | 164 |
| Fossil fuel-fired generation facilities and sites | 104 | 94 |
| **Total environmental remediation liability** | **$ 992** | **$ 969** |

[1] See "Natural Gas Compressor Station Sites" below.

The Utility's environmental remediation liability at September 30, 2016 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to implement final remediation plans and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

At September 30, 2016, the Utility expected to recover $704 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. Some of the Utility's environmental remediation liability, such as the environmental remediation costs associated with the Hinkley site discussed below, will not be recovered in rates.

*Natural Gas Compressor Station Sites*

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as the "Topock site." The Utility also is required to take measures to abate the effects of the contamination on the environment.

*Hinkley Site*

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the Regional Board. On November 4, 2015, the Regional Board adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets.

*Topock Site*

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The DTSC is conducting an additional environmental review of the proposed design, and the Utility anticipates that the DTSC's draft environmental impact report will be issued for public comment in early 2017. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in mid-2017. After the Utility modifies its design in response to the final report, the Utility will seek approval to begin construction of the new in-situ treatment system in late 2017 or early 2018.

*Reasonably Possible Environmental Contingencies*

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $2.0 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition, and cash flows during the period in which they are recorded.

**Nuclear Insurance**

In addition to the nuclear insurance the Utility maintains through the NEIL, the Utility also is a member of the EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non- nuclear event were to occur at Diablo Canyon.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, the current maximum aggregate annual retrospective premium obligation for the Utility is approximately $60 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $2.1 million. For more information about the Utility's NEIL coverage, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

**Resolution of Remaining Chapter 11 Disputed Claims**

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

On September 2, 2016, the Utility's settlement became effective resolving, among other matters, the Utility's claim against the CAISO for $165 million, which includes receivables and interest. Additionally, the Utility agreed to release $66 million of cash from escrow to the California Power Exchange. The settlement resulted in a $231 million reduction to the Disputed claims and customer refunds balance onthe Condensed Consolidated Balance Sheets. The settlement agreement did not result in a refund to customers or an impact to net income.

At September 30, 2016 and December 31, 2015, respectively, the Consolidated Balance Sheets reflected $233 million and $454 million in net claims within Disputed claims and customer refunds as well as $161 million and $228 million of cash in escrow within Restricted cash. On October 13, 2016, the Utility received approval from the bankruptcy court to release the remaining cash held in escrow to unrestricted cash for use by the Utility.

**Tax Matters**

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of September 30, 2016, it is reasonably possible that unrecognized tax benefits will decrease by approximately $70 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

**Purchase Commitments**

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. At December 31, 2015, the Utility hadundiscounted future expected obligations of approximately $50 billion. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.) During the nine months ended September 30, 2016, the Utility entered into several renewable energy power purchase agreements that were approved by the CPUC and completed major milestones with respect to construction, resulting in additional commitments of approximately $406 million over the next 20 years.

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates, terms, and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility is alsosubject to the jurisdiction of other federal, state, and local governmental agencies.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. It should also be read in conjunction with the 2015 Form 10-K.

**Summary of Changes in Net Income and Earnings per Share**

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS on an earnings from operations basis) compared to the same period in the prior year (see "Results of Operations" below). "Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods, including certain pipeline related expenses, certain legal and regulatory related expenses, fines and penalties, Butte fire related costs, and impacts of the 2015 GT&S rate case. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short and long-term operating planning, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| **(in millions, except per share amounts)** | **Earnings (1)** | **EPS (Diluted)** | **Earnings (1)** | **EPS (Diluted)** |
| **Income Available for Common Shareholders - September 30, 2015** | **$ 307** | **$ 0.63** | **$ 740** | **$ 1.53** |
| Fines and penalties | 84 | 0.16 | 497 | 1.03 |
| Pipeline-related expenses | 19 | 0.04 | 38 | 0.08 |
| Legal and regulatory related expenses | 8 | 0.02 | 26 | 0.05 |
| Natural gas matters insurance recoveries | (6) | (0.01) | (29) | (0.06) |
| **Earnings from Operations - September 30, 2015 (2)** | **$ 412** | **$ 0.84** | **$ 1,272** | **$ 2.63** |
| Timing of 2015 GT&S revenue collection (3) | 58 | 0.11 | 58 | 0.11 |
| Growth in rate base earnings | 25 | 0.05 | 76 | 0.15 |
| Timing of taxes (4) | (22) | (0.04) | (103) | (0.20) |
| Nuclear refueling outage | - | - | (30) | (0.06) |
| Regulatory and legal matters | 23 | 0.05 | - | - |
| Gain on disposition of SolarCity stock (5) | - | - | (14) | (0.03) |
| Increase in shares outstanding | - | (0.03) | - | (0.08) |
| Miscellaneous | (25) | (0.04) | (50) | (0.10) |
| **Earnings from Operations - September 30, 2016 (2)** | **$ 471** | **$ 0.94** | **$ 1,209** | **$ 2.42** |
| Butte fire related costs (net of insurance) (6) | (9) | (0.02) | (110) | (0.22) |
| Fines and penalties (7) | (42) | (0.08) | (206) | (0.41) |
| Pipeline-related expenses (8) | (18) | (0.04) | (47) | (0.10) |
| Legal and regulatory related expenses (9) | (14) | (0.03) | (32) | (0.06) |
| GT&S capital disallowance (10) | - | - | (113) | (0.23) |
| **Income Available for Common Shareholders - September 30, 2016** | **$ 388** | **$ 0.77** | **$ 701** | **$ 1.40** |

1) All amounts presented in the table above are tax-adjusted at PG&E Corporation's tax rate of 40.75% except for fines, which are not tax deductible. See footnote (7) below.

2) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in footnotes (6) through (10).

3) Represents the incremental authorized revenue collected through rates beginning August 1, 2016 in accordance with the final phase one decision in the Utility's 2015 GT&S rate case during the three and nine months ended September 30, 2016.

4) Represents the timing of taxes reportable in quarterly financial statements.

5) Represents the gain recognized during the nine months ended September 30, 2015. No comparable gain was recognized in 2016.

(6) The Utility accrued charges of $350 million (before the tax impact of $143 million) for the nine months ended September 30, 2016, related to estimated property damages in connection with the Butte fire, partially offset by $260 million (before the tax impact of $106 million) recorded as probable insurance recoveries recognized during the nine months ended September 30, 2016. No additional charges or recoveries were recognized in the three months ended September 30, 2016 related to third-party claims. The Utility also incurred charges of $16 million (before the tax impact of $7 million) and $96 million (before the tax impact of $39 million) for the three and nine months ended September 30, 2016, respectively, for Utility clean-up, repair, and legal costs associated with the Butte fire.

(7) Represents the impact of the Penalty Decision and other enforcement and litigation matters (see Note 9 of the Notes to the Condensed Consolidated Financial Statements). For the three and nine months ended September 30, 2016, the Utility incurred costs of $59 million (before the tax impact of $23 million) and $294 million (before the tax impact of $119 million), respectively, associated with estimated safety-related cost disallowances imposed by the CPUC in its April 9, 2015 decision in the gas transmission pipeline investigations. Specific projects to be disallowed will be determined in the phase two decision of the 2015 GT&S rate case. In addition, for the three and nine months ended September 30, 2016, the Utility accrued fines, which are not deductible for tax purposes, of $1 million and $26 million, respectively, in connection with the MOD POD in the CPUC's investigation regarding natural gas distribution facilities record-keeping practices and of $3 million for the three and nine months ended September 30, 2016 as a result of the federal criminal trial. In the three and nine months ended September 30, 2016, the Utility also recorded $4 million (before the tax impact of $2 million), for probable disallowance that will be imposed for prohibited ex parte communications.

(8) The Utility incurred costs of $31 million (before the tax impact of $13 million) and $80 million (before the tax impact of $33 million) during the three and nine months ended September 30, 2016, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights of way.

(9) The Utility incurred costs of $23 million (before the tax impact of $9 million) and $54 million (before the tax impact of $22 million) during the three and nine months ended September 30, 2016, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(10) Represents charges of $190 million (before the tax impact of $77 million) of probablecapitaldisallowancesas a result of the finalphase one 2015 GT&S rate case decision that the Utility incurred in the nine months ended September 30, 2016, including $134 million (before the tax impact of $54 million) for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million (before the tax impact of $23 million) for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. No additional charges or recoveries were recognized in the three months ended September 30, 2016. (See "Regulatory Matters" below for more information.)

**Key Factors Affecting Financial Results**

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materially affected by the following factors:

- *The Outcome of Enforcement, Litigation, and Regulatory Matters.* The Utility's future financial results may continue to be impacted by current and future enforcement, litigation and regulatory matters and their outcome, including potential remedial and other measures or designation of one or more independent third-party monitor(s)as a result of the federal criminal trial and debarment proceeding, potential fines associated with the alleged violations of the CPUC's ex parte communication rules, litigation claims related to the Butte fire, and a number of investigations and/or requests for information by government agencies, including in connection with the Utility's self-report related to its atmospheric corrosion inspections. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- *The Timing and Outcome of Ratemaking Proceedings*. There are several rate cases that are currently pending at the CPUC and the FERC.The CPUC approved 2015 GT&S "interim" revenue requirements in its final phase one decision dated June 23, 2016. The authorized revenue requirements are effective retroactive to January 1, 2015. However, the Utility will not be able to record the full revenue requirement increase since January 1, 2015 until after the final phase two decision is issued. On November 1, 2016, the assigned ALJ issued a phase two proposed decision in the 2015 GT&S rate case that applies $689 million of the $850 million San Bruno Penalty disallowance to capital expenditures. (See "Regulatory Matters - 2015 Gas Transmission and Storage Rate Case" below for more information.) Additionally, on August 3, 2016, the Utility and other intervening parties filed a motion with the CPUC seeking approval of a settlement agreement in the Utility's 2017 GRC. The settlement agreement proposes a revenue requirement increase of $88 million for 2017. Under the current schedule, a final CPUC decision is expected in February 2017. (See "Regulatory Matters − 2017 General Rate Case" below for more information.) In addition, on July 29, 2016, the Utility filed a rate case at the FERC requesting a 2017 retail electric transmission revenue requirement. The FERC accepted the Utility's filing on September 30, 2016 and set the proceeding for settlement negotiations. (See "Regulatory Matters −FERC Transmission Owner Rate Cases" below for more information.) The outcome of regulatory proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- *The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures.* The Utility is committed to delivering safe, reliable, sustainable and affordable electric and gas services to its customers. Increasing demands from state laws and policies relating to increased renewable energy resources, the reduction of GHG emissions, the expansion of energy efficiency programs, the development and widespread deployment of distributed generation and self-generation resources, and the development of energy storage technologies have increased pressure on the Utility to achieve

efficiencies in its operations in order to maintain the affordability of its service. In any given year the Utility's ability to earn its authorized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 2016 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the June 23, 2016 final phase one CPUC decision in the Utility's 2015 GT&S rate case establishes various cost caps that will increase the risk of overspend over the rate case cycle. The ultimate amount of unrecovered costs also could be affected by how the CPUC determines in its final phase two decision of the 2015 GT&S rate case which costs are included in determining whether the $850 million shareholder-funded obligation under the Penalty Decision has been met. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- *The Amount and Timing of the Utility's Financing Needs*. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. For the nine months ended September 30, 2016, PG&E Corporation issued $742 million of common stock and used $740 million of the cash proceeds to make equity contributions to the Utility. PG&E Corporation forecasts that it will continue issuing a material amount of equity in future years to support the Utility's capital expenditures. PG&E Corporation may issue additional equity to fund unrecoverable pipeline-related expenses and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances would have a material dilutive impact on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1, Financial Statements and Supplementary Data, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors"in the 2015 Form 10-K and in Part II below under "Item 1A. Risk Factors." In addition, this quarterly report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

**RESULTS OF OPERATIONS**

**PG&E Corporation**

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The following table provides a summary of net income available for common shareholders for the three and nine months ended September 30, 2016 and 2015:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| **(in millions)** | **2016** | **2015** | **2016** | **2015** |
| Consolidated Total | $ 388 | $ 307 | $ 701 | $ 740 |
| PG&E Corporation | 2 | 5 | 5 | 35 |
| Utility | $ 386 | $ 302 | $ 696 | $ 705 |

PG&E Corporation's net income primarily consists of interest expense on long-term debt, income taxes, and other income from investments. Results for the nine months ended September 30, 2015 include approximately $30 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation with no corresponding gains for the same period in 2016.

**Utility**

The tables below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2016 and 2015. The tables separately identify the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs), and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

The Utility's operating results for the three and nine months ended September 30, 2016 and 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

| | **Three Months Ended September 30, 2016** | | | **Three Months Ended September 30, 2015** | | |
|---|---|---|---|---|---|---|
| | Revenues/Costs: | | | Revenues/Costs: | | |
| **(in millions)** | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
| Electric operating revenues | $ 2,086 | $ 1,907 | $ 3,993 | $ 1,907 | $ 1,961 | $ 3,868 |
| Natural gas operating revenues | 621 | 195 | 816 | 516 | 166 | 682 |
| **Total operating revenues** | **2,707** | **2,102** | **4,809** | **2,423** | **2,127** | **4,550** |
| Cost of electricity | - | 1,613 | 1,613 | - | 1,681 | 1,681 |
| Cost of natural gas | - | 80 | 80 | - | 50 | 50 |
| Operating and maintenance | 1,373 | 409 | 1,782 | 1,226 | 396 | 1,622 |
| Depreciation, amortization, and decommissioning | 694 | - | 694 | 653 | - | 653 |
| **Total operating expenses** | **2,067** | **2,102** | **4,169** | **1,879** | **2,127** | **4,006** |
| **Operating income** | **640** | **-** | **640** | **544** | **-** | **544** |
| Interest income [1] | | | 8 | | | 2 |
| Interest expense [1] | | | (209) | | | (191) |
| Other income, net [1] | | | 23 | | | 22 |
| Income before income taxes | | | 462 | | | 377 |
| Income tax provision [1] | | | 73 | | | 72 |
| Net income | | | 389 | | | 305 |
| Preferred stock dividend requirement [1] | | | 3 | | | 3 |
| **Income Available for Common Stock** | | | **$ 386** | | | **$ 302** |

[1] These items impacted earnings for the three months ended September 30, 2016 and 2015.

| (in millions) | Nine Months Ended September 30, 2016 Revenues/Costs: That Impacted Earnings | That Did Not Impact Earnings | Total Utility | Nine Months Ended September 30, 2015 Revenues/Costs: That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
|---|---|---|---|---|---|---|
| Electric operating revenues | $ 5,996 | $ 4,594 | $ 10,590 | $ 5,569 | $ 4,775 | $ 10,344 |
| Natural gas operating revenues | 1,670 | 693 | 2,363 | 1,547 | 775 | 2,322 |
| **Total operating revenues** | **7,666** | **5,287** | **12,953** | **7,116** | **5,550** | **12,666** |
| Cost of electricity | - | 3,719 | 3,719 | - | 3,958 | 3,958 |
| Cost of natural gas | - | 377 | 377 | - | 442 | 442 |
| Operating and maintenance | 4,439 | 1,191 | 5,630 | 3,878 | 1,150 | 5,028 |
| Depreciation, amortization, and decommissioning | 2,090 | - | 2,090 | 1,935 | - | 1,935 |
| **Total operating expenses** | **6,529** | **5,287** | **11,816** | **5,813** | **5,550** | **11,363** |
| **Operating income** | **1,137** | **-** | **1,137** | **1,303** | **-** | **1,303** |
| Interest income [1] | | | 16 | | | 6 |
| Interest expense [1] | | | (614) | | | (567) |
| Other income, net [1] | | | 68 | | | 68 |
| Income before income taxes | | | 607 | | | 810 |
| Income tax (benefit) provision [1] | | | (99) | | | 95 |
| Net income | | | 706 | | | 715 |
| Preferred stock dividend requirement [1] | | | 10 | | | 10 |
| **Income Available for Common Stock** | | | **$ 696** | | | **$ 705** |

[1] These items impacted earnings for the nine months ended September 30, 2016 and 2015.

**Utility Revenues and Costs that Impacted Earnings**

The following discussion presents the Utility's operating results for the three and nine months ended September 30, 2016 and 2015, focusing on revenues and expenses that impacted earnings for these periods.

The Utility has received a final phase one decision in its 2015 GT&S rate case. This decision authorized the revenue requirements that the Utility began to collect through rates beginning August 1, 2016 for the 2015 GT&S rate case period. The Utility will collect, over a 36 month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. However, the Utility will not be able to recognize the full impact of revenues retroactive to January 1, 2015 until the CPUC issues a final phase two decision in this rate case. In addition, accounting rules preclude the Utility from recording the full amount of the revenue requirement increase until 2017. (See "Regulatory Matters" below.)

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased by $284 million, or 12%, and by $550 million, or 8%, in the three and nine months ended September 30, 2016, compared to the same periods in 2015 primarily due to additional base revenues authorized by the CPUC in the 2014 GRC decision and in the 2015 GT&S rate case as discussed above, and by the FERC in the TO rate case. (See "Regulatory Matters" below.)

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings increased by $147 million, or 12%, in the three months ended September 30, 2016 compared to the same period in 2015 primarily due to escalation related to labor, benefits, and service contracts, and accelerated transmission and distribution project work. In addition, the Utility incurred $16 million in charges related to the Butte fire and $4 million in charges recorded in connection with the MOD POD related to the natural gas distribution facilities record-keeping investigation and the federal criminal trial during the three months ended September 30, 2016. These increases were partially offset by approximately $90 million of lower disallowed capital charges related to the Penalty Decision compared to the same period in 2015. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

The Utility's operating and maintenance expenses that impacted earnings increased by $561 million, or 14%, in the nine months ended September 30, 2016 compared to the same period in 2015 primarily due to escalation related to labor, benefits, and service contracts, and accelerated transmission and distribution project work. In addition, the Utility incurred $446 million in charges related to the Butte fire, $190 million in permanently disallowed capital spending (see "Regulatory Matters" below), $50 million in costs related to a scheduled nuclear refueling outage at Diablo Canyon, and $29 million in charges recorded in connection with the MOD POD related to the natural gas distribution facilities record-keeping investigation and the federal criminal trial during the nine months ended September 30, 2016. These increases were partially offset by $500 million in charges associated with the Penalty Decision for fines and customer refunds incurred in the first nine months of 2015 with no corresponding charges in 2016. Additionally, the Utility recorded approximately $260 million in probable insurance recoveries related to the Butte fire in the nine months ended September 30, 2016 as compared to $49 million of insurance recoveries for third-party claims related to the San Bruno accident for the same period in 2015. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

The Utility's future financial statements will continue to be impacted by additional charges associated with the Penalty Decision, costs related to the Butte fire, and unrecoverable pipeline-related expenses. (See "Key Factors Affecting Financial Results" above and Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased by $41 million, or 6%, and by $155 million, or 8%, in the three and nine months ended September 30, 2016 compared to the same periods in 2015. These increases were primarily due to the impact of capital additions as authorized by the CPUC in the 2014 GRC decision.

*Interest Expense*

The Utility's interest expenseincreased by $18 million, or 9%, and by $47 million, or 8%, in the three and nine months ended September 30, 2016 compared to the same periods in 2015. These increases were primarily driven by higher levels of long term debt and short term borrowings in 2016 compared to the same periods in 2015.

*Interest Income and Other Income, Net*

There were no material changes to interest income and other income, net for the periods presented.

*Income Tax Provision*

The income tax provision increased by $1 millionin the three months ended September 30, 2016 and decreased by $194 million in the nine months ended September 30, 2016 as compared to the same periods in 2015. The following describes the changes in the Utility's effective tax rate for the three and nine months ended September 30, 2016 as compared to the same periods in 2015:

The effective tax rates for the three months ended September 30, 2016 and 2015 were 16% and 19%, respectively. The decrease in the effective tax rate was primarily due to higherbenefits resulting from various property-related tax deductions recorded during the three months ended September 30, 2016 with lower comparable amounts in the three month period ending September 30, 2015.

The effective tax rates for the nine months ended September 30, 2016 and 2015 were (16)% and 12%, respectively. The decrease in the effective tax rate was primarily due to higherbenefits resulting from various property-related tax deductions recorded during the nine months ended September 30, 2016 with lower comparable amounts in the nine month period ending September 30, 2015, as well asbenefits resulting from various tax audit results recorded during the nine months ended September 30, 2016 with no comparable amounts in the nine month period ending September 30, 2015.

**Utility Revenues and Costs that did not Impact Earnings**

Fluctuations in revenues that did not impact earnings are primarily driven by electricity and natural gas procurement costs. See below for more information.

*Cost of Electricity*

TheUtility's cost of electricity includes the costs of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| **(in millions)** | **2016** | | **2015** | | **2016** | | **2015** | |
| Cost of purchased power | $ | 1,541 | $ | 1,605 | $ | 3,540 | $ | 3,734 |
| Fuel used in own generation facilities | | 72 | | 76 | | 179 | | 224 |
| **Total cost of electricity** | **$** | **1,613** | **$** | **1,681** | **$** | **3,719** | **$** | **3,958** |
| Average cost of purchased power per kWh [1] | $ | 0.123 | $ | 0.111 | $ | 0.110 | $ | 0.105 |
| Total purchased power (in millions of kWh) [2] | | 12,560 | | 14,424 | | 32,327 | | 35,462 |

(1) Average cost of purchased power for the three and nine months ended September 30, 2016 increased compared to the same periods in 2015 primarily due to a higher percentage of renewable energy resources.

(2) The decrease in purchased power for the three and nine months ended September 30, 2016 resulted from an increase year-to-date in generation from the Utility's own generation facilities and lower electric customer demand. Hydroelectric generation increased during the three and nine months ended September 30, 2016 as compared to the same periods in 2015.

The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including the Diablo Canyon nuclear generation power plant and hydroelectric plants), and the cost-effectiveness of each source of electricity.

*Cost of Natural Gas*

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of transportation and storage, and changes in customer demand.

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| **(in millions)** | **2016** | | **2015** | | **2016** | | **2015** | |
| Cost of natural gas sold | $ | 50 | $ | 18 | $ | 275 | $ | 335 |
| Transportation cost of natural gas sold | | 30 | | 32 | | 102 | | 107 |
| **Total cost of natural gas** | **$** | **80** | **$** | **50** | **$** | **377** | **$** | **442** |
| Average cost per Mcf [1] of natural gas sold [2] | $ | 1.79 | $ | 0.69 | $ | 1.88 | $ | 2.46 |
| Total natural gas sold (in millions of Mcf) [1] | | 28 | | 26 | | 146 | | 136 |

(1) One thousand cubic feet

(2) Average cost of natural gas sold was primarily impacted by fluctuations in the market price of natural gas in the three and nine months ended September 30, 2016 compared to the same periods in 2015.

*Operating and Maintenance Expenses*

The Utility's operating expenses also include certain recoverable costs that the Utility incurs as part of its operations such as pension contributions and public purpose programs costs. If the Utility were to spend over authorized amounts, these expenses could have an impact on earnings.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its cost of capital. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends primarily depends on the level of cash distributions received from the Utility's and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and issuances and repayments under its revolving credit facility and commercial paper program. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue approximately $800 million in common stock during 2016 and between $400 million and $600 million during 2017, primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by the timing and outcome of the final phase two decision in the 2015 GT&S rate case, by unrecoverable pipeline-related expenses, and by fines, penalties and claims that may be imposed in connection with the matters described in "Enforcement and Litigation Matters" below. Common stock issuances by PG&E Corporation to fund these needs would have a material dilutive impact on PG&E Corporation's EPS.

### Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceedings under Chapter 11 of the U.S. Bankruptcy Code. As part of the settlement approved in the third quarter of 2016, the Utility agreed to release $66 million of cash from escrow to the California Power Exchange. Additionally, on October 13, 2016, the Utility received approval from the bankruptcy court to release the remaining $161 million of cash held in escrow to unrestricted cash for use by the Utility. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

### Financial Resources

#### *Debt and Equity Financings*

During the three and nine months ended September 30, 2016, PG&E Corporation sold 0.4 million and 2.6 million shares of its common stock under the February 2015 equity distribution agreement for cash proceeds of $26 million and $149 million, respectively, net of commissions paid of $0.2 million and $1.3 million, respectively. As of September 30, 2016, the remaining gross sales available under this agreement were $275 million.

In August 2016, PG&E Corporation sold 4.9 million shares of its common stock in an underwritten public offering for net cash proceeds of $309 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the nine months ended September 30, 2016, 5.7million shares were issued for cash proceeds of $269 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility. For the nine months ended September 30, 2016, PG&E Corporation made equity contributions to the Utility of $740 million.

In March 2016, the Utility issued $600 million principal amount of 2.95% Senior Notes due March 1, 2026. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper. In addition, in March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

***Revolving Credit Facilities and Commercial Paper Program***

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021. At September 30, 2016, PG&E Corporation and the Utility had $135 million and $2.2 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements.)

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $1.75 billion, respectively. For the nine months ended September 30, 2016, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $76 million and $869 million, and a maximum outstanding balance of $176 million and $1.4 billion, respectively. At September 30, 2016, PG&E Corporation and the Utility had an outstanding commercial paper balance of $165 million and $731 million, respectively.

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At September 30, 2016, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51% and 49%, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At September 30, 2016, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

***Dividends***

In May 2016, the Board of Directors of PG&E Corporation and the Utility each adopted a new target dividend payout ratio range of 55% to 65% of earnings, with a target to reach a payout ratio of approximately 60% by 2019. Each Board of Directors retains authority to change the respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

In September 2016, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.49 per share, totaling $248 million, of which approximately $243 million was paid on October 15, 2016, to shareholders of record on September 30, 2016.

In September 2016, the Board of Directors of the Utility declared a common stock dividend of $244 million that was paid to PG&E Corporation on October 3, 2016.

In September 2016, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on November 15, 2016, to shareholders of record on October 31, 2016.

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Nine Months Ended September 30, | |
|---|---|---|
| **(in millions)** | **2016** | **2015** |
| Net cash provided by operating activities | $ 3,206 | $ 2,932 |
| Net cash used in investing activities | (4,083) | (3,734) |
| Net cash provided by financing activities | 886 | 809 |
| **Net change in cash and cash equivalents** | **$ 9** | **$ 7** |

***Operating Activities***

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During the nine months ended September 30, 2016, net cash provided by operating activities increased by $274 million compared to the same period in 2015. This increase was primarily due to tax refunds of $151 million received during 2016 compared to no tax refunds received or tax payments made during 2015. The remaining increase was primarily due to fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections and vendor billings and payments.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and amounts of costs that may be incurred in connection with potential remedial and other measures that may be imposed on the Utility as a result of the jury's verdict in the federal criminal trial and in connection with the DOI debarment proceeding, and fines or penalties that may be imposed in connection with the remaining investigations and other enforcement and litigation matters and the timing and amount of related insurance recoveries (see Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and outcome of ratemaking proceedings, including of a final phase two decision in the 2015 GT&S rate case, the 2017 GRC, and the TO rate cases;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system;
- the timing and amount of tax payments (including the bonus depreciation), tax refunds, net collateral payments, and interest payments; and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

***Investing Activities***

Net cash used in investing activities increased by $349 million during the nine months ended September 30, 2016 as compared to the same period in 2015. The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately$5.7 billion in capital expenditures in 2016 and approximately $6.0 billion in each of the years 2017, 2018 and 2019.

***Financing Activities***

During the nine months ended September 30, 2016, net cash provided by financing activities increased by $77 million compared to the same period in 2015. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

## ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 9 of the Notes to the Condensed Consolidated Financial Statements. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2015 Form 10-K and "Part II. Other Information, Item 1. Legal Proceedings." Significant regulatory developments that have occurred since the 2015 Form 10-K was filed with the SEC are discussed below.

### *Department of Interior Inquiry*

In September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the San Bruno explosion and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. The Utility filed its initial response on November 2, 2015 to demonstrate that it is a "presently responsible" contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate. On April 8, 2016, the Utility received a series of follow-up questions from the DOI regarding its November 2015 submission. The Utility continues to fully cooperate with the DOI and is addressing its questions.

As a result of the August 9, 2016 jury's verdict in the federal criminal trial, the Utility updated its registration on the federal government's System for Award Management (SAM), a federal procurement database, to reflect the verdict. (The federal criminal trial is discussed in Note 9 of the Notes to the Condensed Consolidated Financial Statements and in Item 1 Legal Proceedings.) The Utility does not believe that the updated registration will affect its existing contracts with the federal government, but it does affect execution of new contracts with the federal government. Under federal law, the government may not enter into a contract with any corporation that was convicted of a felony criminal violation under any federal law within the preceding 24 months, where the awarding agency is aware of the conviction, unless an agency has considered suspension or debarment of the corporation and made a determination that this action is not necessary to protect the interests of the government.

Following the update of the SAM, the Utility and the DOI have been in discussions regarding such a determination and a possible interim administrative agreement that would allow the federal government agencies to contract with the Utility while the DOI is completing its debarment inquiry. It is uncertain when and if the Utility and the DOI will enter into an interim administrative agreement. It is also uncertain when or if further action will be taken by the DOI. The DOI debarment inquiry could result in the Utility's suspension or debarment from future federal government contracts for a fixed, specified time period or entering into an administrative agreement with the DOI to resolve debarment matters.

As a result of the DOI inquiry and/or of the August 9, 2016 jury's guilty verdict on six felony counts in the federal criminal trial, the Utility may be required to implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third party monitor(s). If appointed, the Utility expects a monitor or monitors would serve for a period of time and report periodically to the court or a department or agency of the government. The Utility could incur material costs, not recoverable through rates, to implement remedial and other measures that could be imposed, the amount of which the Utility is currently unable to estimate.

### *Litigation Related to the San Bruno Accident and Natural Gas Spending*

As of September 30, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the *San Bruno Fire Derivative Cases* and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are *Tellardin v. PG&E Corp. et al., Iron Workers Mid-South Pension Fund v. Johns, et al.,* and *Bushkin v. Rambo et al*.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated *San Bruno Fire Derivative Cases* pending conclusion of the federal criminal proceedings against the Utility. On September 16, 2016, the San Mateo Superior Court requested that all counsel appear for a status conference in the consolidated matter. The date of the conference has been set for November 16, 2016.

*Bushkin v. Rambo et al*., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit *Iron Workers Mid-South Pension Fund v. Johns, et al.*, discussed below. The plaintiff in the *Bushkin* lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the *Bushkin* plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the Court to dismiss plaintiff's petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation's motion, and indicated that plaintiff's petition was stayed pending resolution of the criminal matter against the Utility.

The *Iron Workers* action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the *San Bruno Fire Derivative Cases*. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court's request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the *San Bruno Fire Derivative Cases*. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the stay pending the resolution of the criminal proceedings against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017.

A case management conference in the action entitled *Tellardin v. PG&E Corp. et al.,* also pending in the Superior Court of California, San Mateo County, had been scheduled for August 9, 2016. On July 19, 2016, plaintiff requested that the court vacate the August 9, 2016 conference because, pursuant to the parties' agreement, defendants are not required to respond to the complaint in this action until 30 days after an order lifting the stay in the *San Bruno Fire Derivative Cases*. On August 2, 2016, the court vacated the August 9, 2016 conference.

The federal criminal proceeding is still pending. For more information about the federal criminal proceeding, see Note 9 of the Notes to the Condensed Consolidated Financial Statements and Item 1 Legal Proceedings.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

**REGULATORY MATTERS**

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. Significant regulatory developments that have occurred since the 2015 Form 10-K was filed with the SECare discussed below.

**2017 General Rate Case**

On August 3, 2016, the Utility, together with ORA, TURN, and 12 other intervening parties filed a motion with the CPUC seeking approval of a settlement agreement that resolves nearly all of the issues raised by the parties in the Utility's 2017 GRC. All parties who filed testimony in the case joined the settlement agreement, which was the subject of a one-day workshop overseen by the assigned commissioner and ALJ. The settlement agreement will ultimately be considered by the full commission. In the GRC proceeding, the CPUC will determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. (The Utility's revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.) In its GRC application, the Utility requested an overall increase in electric distribution, natural gas distribution, and utility-owned electric generation revenue requirements of $319 million over currently authorized amounts (as updated through the Utility's May 27, 2016 rebuttal testimony), effective January 1, 2017.

*Revenue Requirements and Attrition Year Revenues*

The settlement agreement proposes that the Utility's 2016 authorized revenue requirement of $7.9 billion be increased by $88 million, effective January 1, 2017. The settlement agreement further provides for an increase to the authorized 2017 revenues of $444 million in 2018 and an additional increase of $361 million in 2019, as shown in the table below.

The settlement agreement identifies two contested issues. First, the parties were unable to agree on whether there should be a third post-test year or "attrition" year for this GRC cycle. ORA and the Utility recommend a third post-test year for this cycle that would provide for an additional increase of $361 million. TURN and certain other settling parties oppose the third post-test year. The other contested issue concerns whether the Utility should be authorized to establish a new balancing account for costs arising from the CPUC's rulemaking on natural gas leak abatement. The Utility and certain settling parties support the balancing account. TURN and certain other settling parties do not. ORA does not oppose it. Interested parties filed comments and reply comments on the contested issues and these issues were also discussed at the one-day workshop.

The table below summarizes the differences between the amount of revenue requirement increases included in the Utility's request, as updated in the Utility's supplemental testimony filed on February 22, 2016 and its May 27, 2016 rebuttal testimony, and the amount proposed in the settlement agreement:

| Year | | Increase Requested in GRC Application (in millions) | | Increase Proposed in Settlement Agreement (in millions) | | Difference[1] (Decrease from GRC Application) (in millions) |
|---|---|---|---|---|---|---|
| 2017 | $ | 319 | $ | 88 | $ | (231) |
| 2018 | | 467 | | 444 | | (23) |
| 2019 | | 368 | | 361 | | (7) |
| 2020[2] | | N/A | | 361 | | N/A |

[1] Rounded for presentation purposes.
[2] Whether or not revenues should be authorized for 2020 is a contested issue.

The following table shows the difference between the Utility's requested increases in 2017 revenue requirements by line of business and the amounts proposed in the settlement agreement:

| **(in millions)** **Line of Business:** | | **Increase Requested in GRC Application** | | | **Increase/(Decrease) Proposed in Settlement Agreement** | | | **Difference[1] (Decrease from GRC Application)** |
|---|---|---|---|---|---|---|---|---|
| Electric distribution | $ | 67 | 1.6 % | $ | (62) | (1.5) % | $ | (128) |
| Gas distribution | | 59 | 3.4 | | (3) | (0.2) | | (62) |
| Electric generation | | 193 | 9.9 | | 153 | 7.8 | | (40) |
| **2017 revenue requirement increases** | **$** | **319** | **4.0 %** | **$** | **88** | **1.1 %** | **$** | **(231)** |

[1] Rounded for presentation purposes.

The following table shows the differences, by line of business and cost category, between the amount of revenue requirements included in the GRC application and the amount proposed in the settlement agreement, as well as the differences between the 2016 authorized revenue requirements and (i) the GRC application and (ii) the amounts proposed in the settlement agreement:

| (in millions) [1]<br>**Line of Business:** | **Amounts Requested in 2017 GRC Application** | **Amounts Proposed in Settlement Agreement** | **Difference (Decrease)** | **Increase/ (Decrease) 2016 Amounts vs. 2017 GRC Application** | **Increase/ (Decrease) 2016 Amounts vs. Settlement Agreement** |
|---|---|---|---|---|---|
| Electric distribution | $ 4,279 | $ 4,151 | $ (128) | $ 67 | $ (62) |
| Gas distribution | 1,801 | 1,738 | (62) | 59 | (3) |
| Electric generation | 2,155 | 2,115 | (40) | 193 | 153 |
| **Total revenue requirements** | **$ 8,235** | **$ 8,004** | **$ (231)** | **$ 319** | **$ 88** |
| | | | | | |
| **Cost Category:**<br>(in millions) [1] | | | | | |
| Operations and maintenance | $ 1,825 | $ 1,794 | $ (31) | 161 | 131 |
| Customer services | 361 | 334 | (27) | 42 | 15 |
| Administrative and general | 975 | 912 | (62) | (36) | (99) |
| Less: Revenue credits | (140) | (152) | (12) | (9) | (21) |
| Franchise fees, taxes other than income, and other adjustments | 184 | 170 | (14) | 146 | 132 |
| Depreciation (including costs of asset removal), return, and income taxes | 5,030 | 4,946 | (84) | 15 | (70) |
| **Total revenue requirements** | **$ 8,235** | **$ 8,004** | **$ (231)** | **$ 319** | **$ 88** |

[1] Rounded for presentation purposes.

The settlement agreement proposes reductions in the following areas forecast in the GRC application. For gas distribution, reductions are proposed for corrosion control, leak management, gas operations technology, and new business. For electric distribution, reductions are proposed for overhead maintenance, capacity, technology, mapping and records, reliability, substation management, new business, and undergrounding work. For electric distribution, the capital-related reductions are offset in part by increases in the replacement and installation of additional units in specific asset areas. For electric generation, the settlement agreement proposes to move costs related to Diablo Canyon seismic studies from the GRC to the Utility's Energy Resource Recovery Account proceeding. Proposed reductions in the customer service area largely relate to the removal of certain costs from the forecast related to residential rate reform implementation. Some of these costs would be recoverable through the existing Residential Rates Reform Memorandum Account, and the Utility could seek recovery of the remaining costs in a future filing with the CPUC. Additionally, a number of company-wide reductions, including reductions to the Short-Term Incentive Plan and certain employee benefits, are proposed in the settlement agreement.

*Balancing Accounts*

The settlement agreement proposes to retain certain existing balancing accounts, including the Tax Act Memo Account that was first established following the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, and to eliminate certain memorandum and balancing accounts that are no longer necessary. In addition to the contested balancing account for natural gas leak abatement mitigation costs, the settlement agreement proposes one new tax-related memorandum account to track the impact on the revenue requirement from certain types of changes in tax laws or regulations.

*Capital Additions and Rate Base*

The settlement agreement proposes capital expenditures of $3.9 billion for 2017 for the portions of the Utility's business addressed in the GRC. Proposed capital expenditures are lower than the amount included in the GRC application of $4.0 billion for 2017, consistent with the provisions of the settlement agreement. While the settlement agreement proposes overall revenue requirement increases for 2018 and 2019, it does not specify capital expenditures for those years.

The settlement agreement proposes a 2017 weighted average rate base of $24.3 billion for the portions of the Utility's business reviewed in the GRC, compared with the Utility's request of $24.5 billion. The $200 million difference is primarily due to the lower level of capital expenditures agreed to in the settlement.

On August 30, 2016, the CPUC held a workshop to allow the assigned CPUC commissioner, the assigned ALJ, and other interested parties to pose questions to the Utility and other settling parties regarding the settlement agreement. The Utility and the parties also discussed post-test years 2018 and 2019, including imputed capital additions and rate base amounts, and the two contested issues: a third post-test year or "attrition" year for this GRC cycle (i.e. for 2020) and whether the Utility should be authorized to establish a new balancing account for costs arising from the CPUC's rulemaking on natural gas leak abatement. The Utility estimated authorized capital expenditures of $3.6 billion for 2018 and $3.5 billion for 2019, based on a calculation method that is subject to CPUC approval, as compared to its request of approximately $4.0 billion each year. The Utility is unable to predict if the CPUC will approve its proposed calculation method. The Utility also estimateda weighted average rate base of $25.4 billion for 2018 and $26.3 billion for 2019, compared with the Utility's request of $25.7 billion and $26.9 billion, respectively.

Evidentiary hearings were held on September 1, 2016. Under the current schedule, a proposed decision is expected to be released in January 2017, and a final CPUC decision is expected to be issued in February 2017. On March 17, 2016, the CPUC issued a decision to allow the authorized revenue requirement changes to become effective on January 1, 2017, even if the final decision is issued after that date.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the settlement agreement.

For more information, see Item 4 of the 2015 Form 10-K and Item 2 of the 2016 Q1 Form 10-Q and the 2016 Q2 Form 10-Q.

**2015 Gas Transmission and Storage Rate Case**

On June 23, 2016, the CPUC approved a final decision in phase one of the Utility's 2015 GT&S rate case. The decision adopts the "interim" revenue requirements that the Utility is authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period (see table below). The decision authorizes the Utility to collect, over a 36-month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. The Utility will not be able to record the full revenue requirement increase since January 1, 2015 until after the final phase two decision is issued. In addition, accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. As a result, the Utility will not be able to complete recording the full retroactive revenue requirement increase in 2016.

The phase one decision adopts capital expenditures of roughly $700 million to $800 million per year through 2018 and authorizes weighted average rate base of $2.9 billion in 2015, $3.3 billion in 2016, $3.6 billion in 2017, and $4.2 billion in 2018, before the application of the shareholder-funded safety work disallowance associated with the Penalty Decision. The authorized weighted average rate base excludes $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallows $120 million of that amount and orders that the remaining $576 million be subject to a third party audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also establishes various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way capital balancing accounts. As a result, in the second quarter of 2016, the Utility incurred charges of $190 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This includes $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the third party audit of 2011 through 2014 capital spending.

The phase one decision denies the Utility's request for full balancing account treatment for recovery of authorized transportation and storage revenue requirements, and instead continues the revenue sharing mechanism authorized in the 2011 GT&S rate case that subjects a portion of the Utility's transportation and storage revenue requirement to market risk.

The phase one decision also authorizes the Utility's request for cost recovery of up to $157 million for the construction of Line 407, a 25.5 mile, 30-inch pipeline in the Sacramento Valley expected to be built during this rate case period. The authorized revenue requirements will begin when Line 407 becomes operational, subject to refund upon a reasonableness review in the Utility's next GT&S rate case. The decision authorizes the Utility to track costs exceeding $157 million and seek recovery in the next GT&S rate case, subject to a reasonableness review.

On November 1, 2016, the assigned ALJ issued a phase two proposed decision ("phase two PD") regarding the $850 million penalty assessed in the Penalty Decision. In accordance with the phase one decision, the phase two PD would first reduce the recommended revenue requirement by the $850 million San Bruno penalty to determine the revenue requirement to be collected from customers, and then apply the ex parte disallowance. The phase two PD would apply $689 million of the $850 million penalty (81 percent) to capital expenditures and the remaining $161 million (19 percent) to expenses, and then reduce the 2015 revenue requirement by $72 million for the 5-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding.

Accordingly, the phase two PD would adopt a 2015 revenue requirement of $815 million, a 2016 revenue requirement of $1.061 billion, a 2017 revenue requirement of $1.125 billion, and a 2018 revenue requirement of $1.230 billion. These amounts reflect attrition increases of $246 million in 2016, $64 million in 2017, and $105 million in 2018. Excluding the $161 million for the expense portion of the Penalty Decision disallowance and the $72 million ex parte disallowance, the attrition increase would be $13 million in 2016.

The following table shows the revenue requirement amounts requested by the Utility in the 2015 GT&S rate case, the "interim" revenue requirement amounts adopted in the phase one decision, and the revenue requirement amounts recommended in the phase two PD, including adjustments for the $850 million Penalty Decision disallowance and the ex parte disallowance:

| (in millions) | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|
| Utility Requested Revenue Requirement | $ 1,263 | $ 1,346 | $ 1,488 | $ N/A |
| | | | | |
| Phase One Decision "Interim" Revenue Requirement | 1,046 | 1,110 | 1,220 | 1,324 |
| San Bruno Penalty Expense Allocation | (161) | | | |
| San Bruno Penalty Capital Revenue Requirement Allocation | 5 | (47) | (93) | (93) |
| Other Expense Adjustments | (3) | (2) | (2) | (1) |
| Adjusted Ex Parte Penalty | (72) | | | |
| Phase Two PD Revenue Requirement | $ 815 | $ 1,061 | $ 1,125 | $ 1,230 |

The phase two PD also recommends weighted average rate base reductions of $99 million in 2015, $453 million in 2016, $670 million in 2017, and $658 million in 2018, resulting in total weighted average rate base of $2.8 billion in 2015, $2.8 billion in 2016, $3.0 billion in 2017, and $3.5 billion in 2018. The proposed decision would reduce rate base by the full amount of the disallowed capital expenditures but would not remove the associated deferred taxes, resulting in a larger rate base reduction. It is unclear whether this treatment would apply beyond this rate case period.

In addition, the phase two PD would approve the Utility's list of programs which meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty.

Opening briefs on the phase two PD are due on November 21, 2016 and reply briefs are due on November 28, 2016. The final phase two decision is expected to be issued within 30 days of the reply briefs. With the addition of a third attrition year, the Utility's next GT&S cycle will begin in 2019. The decision requires the Utility to file its next GT&S application in 2017.

For more information, see Item 4 of the 2015 Form 10-K and Item 2 of the 2016 Q1 Form 10-Q and the 2016 Q2 Form 10-Q.

**FERC Transmission Owner Rate Cases**

On July 29, 2015, the Utility requested a 2016 retail electric transmission revenue requirement of $1.515 billion, a $314 million increase over the currently authorized revenue requirement of $1.201 billion. The Utility's proposed rates went into effect on March 1, 2016, subject to refund, and pending a final decision by the FERC. On September 1, 2016, the Utility and other settling parties (including the CPUC) filed a motion at the FERC for approval of a settlement proposing that the Utility's 2016 retail electric transmission revenue requirement be set at $1.331 billion, a $130 million increase over the currently authorized revenue requirement. The settlement is subject to the FERC's approval. The Utility also filed a motion on September 1, 2016, requesting the implementation of interim rates that, as of result of the settlement, became effective for wholesale customers on September 1, 2016 and for retail customers on October 1, 2016, subject to refund and pending a final decision by the FERC. The FERC is expected to issue a decision in late 2016 or early 2017.

On July 29, 2016, the Utility filed a rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of $1.718 billion, a $203 million increase over the 2016 requested revenue requirement of $1.515 billion (and a $387 million increase over the pending settlement revenue requirement of $1.331 billion). The forecasted network transmission rate base for 2017 is $6.7 billion, compared to a forecasted rate base of $5.85 billion in 2016. The Utility is also seeking a return on equity of 10.9% which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted that it will make investments of $1.296 billion in 2017 in various capital projects.

On September 30, 2016, the FERC issued an order accepting the Utility's July 2016 filing and set it for settlement negotiations. The order set an effective date for rates of March 1, 2017, and made the rates subject to hearing and refund. The first settlement conference took place on October 19, 2016. The next settlement conference is scheduled for February 7 and February 8, 2017.

**CPUC Cost of Capital Decision**

On February 25, 2016, the CPUC issued a decision granting a petition for modification filed by the Utility and the other two California investor-owned electric utilities to clarify that the CPUC's previously adopted cost of capital adjustment mechanism would not be triggered before their 2018 cost of capital applications are due on April 20, 2017. As a result, the Utility's currently authorized return on equity of 10.40% and capital structure, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock, will remain the same for 2017.

**Diablo Canyon Nuclear Power Plant**

*Joint Proposal for Plant Retirement*

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application implements a joint proposal between the Utility and the Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and Alliance for Nuclear Responsibility.

The application and joint proposal include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables. The parties to the joint proposal proposed that the Utility be authorized to procure GHG-free replacement resources in three competitive procurement tranches: in Tranche 1, the Utility would be authorized to obtain 2,000 gross GWh of energy efficiency savings to be implemented over the 2018 to 2024 time period; in Tranche 2, the Utility would be authorized to procure through a solicitation 2,000 GWh of GHG-free energy resources that will commence energy deliveries or add energy efficiency projects to the system in the 2025 to 2030 time period; and in Tranche 3, the Utility would commit to a voluntary 55% RPS, and would maintain this voluntary commitment through 2045 or until superseded by action of the state legislature or the CPUC. The three tranches of resource procurement in the application and joint proposal are not intended to specify all energy resources that will be needed to ensure the orderly replacement of Diablo Canyon. Instead, the Utility expects that the full solution will be addressed in ongoing CPUC proceedings.

Costs associated with energy efficiency projects or programs in Tranche 1 and Tranche 2 would be recovered through the Utility's electric public purpose program rates as non-bypassable charges, consistent with the existing recovery mechanisms for energy efficiency program costs. GHG-free energy resources costs from Tranche 2 are proposed to be recovered through a non-bypassable cost allocation mechanism called the Clean California Charge that (1) equitably allocates costs and benefits, such as RPS or Resource Adequacy credits, associated with the procurement among responsible load-serving entities, and (2) determines the net capacity costs of such procurement consistent with the methodology for the allocation of net capacity costs laid out by the CPUC. Costs associated with procurement for Tranche 3 would be recovered through a separate renewable non-bypassable charge.

The application seeks confirmation from the CPUC that the Utility's full investment in Diablo Canyon and authorized rate of return will be recovered in rates by the time the facility ceases operations. Additionally, the Utility requests that the CPUC pre-approve the recovery of certain costs related to the closure of the Diablo Canyon. These include the non-bypassable cost allocation mechanism for procurement of GHG-free energy and the recovery of $1.3 billion for administration and acquisition of the new Tranche 1 energy efficiency procurement as authorized energy efficiency funding, subject to return of all unspent funds; the recovery of employee retention and retraining and development programs to continue safe and efficient operation of Diablo Canyon through the end of its license periods, estimated at approximately $350 million; and a community mitigation program to compensate San Luis Obispo County for the decline in local economic stimulus provided by Diablo Canyon through a transition period ending in 2025, estimated at approximately $50 million. The Utility also seeks cost recovery of approximately $50 million in costs related to the federal and state Diablo Canyon license renewal process.

More than 40 parties have submitted responses and protests to the Utility's application. A prehearing conference on the application was held on October 6, 2016. The ALJ heard arguments on the scope of issues to be addressed in the proceeding and stated he would issue a scoping order after the public participation hearings that were held in San Luis Obispo on October 20, 2016. On October 27, 2016, the ALJ issued a ruling requiring the Utility to submit supplemental testimony related to Diablo Canyon land ownership no later than November 18, 2016. The Utility expects that a final decision will be issued by the end of 2017. Upon CPUC approval of the application, the Utility will withdraw its license renewal application currently pending before the NRC when such approval has become final and non-appealable. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the application.

*California State Lands Commission Lands Lease*

On June 28, 2016, California State Lands Commission approved a new lands lease for the intake and discharge structures at Diablo Canyon to run concurrently with Diablo Canyon's current operating licenses, until Diablo Canyon Unit 2 ceases operations in August 2025. The Utility believes that the approval of the new lease will ensure sufficient time for the Utility to identify and bring online a portfolio of GHG-free replacement resources. The Utility will submit a future lease extension request to address the period of time required for plant decommissioning, which under NRC regulations can take as long as 20 years. On August 28, 2016, the World Business Academy (WBA) filed a writ in the Los Angeles Superior Court. WBA asserts that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act. If the petitioner prevails in its challenge, the State Lands Commission could be required to perform an environmental review of the new lands lease. No schedule has been set for consideration of the writ at this time but the Utility expects a ruling in the first half of 2017.

*Asset Retirement Obligations*

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion, for a total estimated cost of $4.8 billion, due to increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates. Additionally, as a result of the joint proposal discussed above, an increase of $115 million to the ARO was recognized on the Utility's Condensed Consolidated Balance Sheetsin the second quarter of 2016.

While the NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the joint proposal's employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program described above. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study to the CPUC by mid-2019.

On July 15, 2016, the assigned CPUC commissioner and ALJ issued a scoping memo for the Utility's 2015 NDCTP and excluded from the scope of the proceeding the issue on whether the Utility should be required to present additional analysis for a license extension scenario for Diablo Canyon, as a result of the Utility's announcement of its plan to not seek relicensing of Diablo Canyon beyond its current operating authority. The scoping memo also adopts within the scope of the proceeding a reasonableness review of the Utility's estimated updated cost to decommission the Utility's nuclear power plants and of the forecasts of certain expenses and the decommissioning trust funds' rates of return. Evidentiary hearings took place in September 2016 and opening briefs were submitted on October 14, 2016. Intervenor parties proposed several major recommendations including a reduction to the total spent nuclear fuel storage forecast, a reduction to the large component (reactor vessels, steam generators, and other large plant components) removal cost estimate, and a reduction to the waste disposal estimate. Additionally, intervenors asserted that the CPUC should not permit the Utility to increase its Diablo Canyon-related revenue requirement at this time as it has not demonstrated its current estimate is reasonable. Parties also claimed that the Utility has not justified its increase to security costs and decommissioning oversight contractor staff costs. No party challenged the Utility's decommissioning trust funds rates of return or cost escalation assumptions. Reply briefs were submitted on October 31, 2016. Intervenor parties reiterated that the Utility has not justified increases in costs due to large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility confirmed that the testimony and work papers support the cost increases as well as the total estimate to decommission Diablo Canyon.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.5 billion at September 30, 2016, which includes an $818 million adjustment to reflect the increased cost estimates and the $115 million increase resulting from the joint proposal described above, and $2.5 billion at December 31, 2015. These estimates are based on decommissioning cost studies, prepared in accordance with the CPUC requirements. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

As of September 30, 2016, the nuclear decommissioning trust accounts' total fair value was $2.9 billion. Changes in the estimated costs, the timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission.

For additional information, see the 2015 Form 10-K, the 2016 Q1 Form 10-Q, and the 2016 Q2 Form 10-Q.

**CPUC Investigation of the Utility's Safety Culture**

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment. The consultant's work began in the second quarter of 2016.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned commissioner will determine the scope of and next actions in the proceeding. The timing, scope and potential outcome of the investigation are uncertain.

**Rehearing of CPUC Decisions Approving 2006 - 2008 Energy Efficiency Incentive Awards**

On September 17, 2015, the CPUC granted TURN's and ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California IOUs for the 2006-2008 energy efficiency program cycle. Under the incentive ratemaking mechanism applicable to the 2006-2008 program cycle, the Utility could have earned incentive revenues up to a maximum of $180 million, depending on the extent to which the Utility achieved the energy savings targets. Conversely, to the extent the Utility failed to achieve the targets, the Utility could have been required to offset future incentive earnings claims by amounts previously awarded, and, in addition, could have incurred penalties of up to $180 million. The Utility was awarded a total of $104 million for the 2006-2008 program cycle.

On September 15, 2016, the CPUC approved a settlement agreement filed by the Utility, ORA, and TURN to resolve all issues related to the 2006-2008 customer energy efficiency shareholder incentives. The final decision requires the Utility to reduce future energy efficiency shareholder incentives by $29.1 million. The reduction of the shareholder incentive award will be applied in installments of $5.8 million per year for five years, provided that the Utility has sufficient energy efficiency incentive awards to offset that amount. If shareholder incentives are insufficient to offset this amount, the offset in the following year will be increased by the shortfall. At its discretion, the Utility may increase the amount of the offset to reduce the $29.1 million more quickly. If the amount has not been fully offset at the end of five years, the balance will be credited against future energy efficiency program spending. The first offset was requested by the Utility in the September 1, 2016 shareholder incentive advice letter related to the 2014-2015 Energy Efficiency Incentive Awards (see below).

**2014-2015 Energy Efficiency Incentive Awards**

On September 1, 2016, the Utility filed an advice letter with the CPUC requesting a shareholder incentive award for a portion of the energy savings it achieved through its energy efficiency programs in the 2014 and 2015 program years. The Utility requested $24.9 million, and further requested that this amount be reduced by $5.8 million as a result of the settlement agreement related to the 2006-2008 energy efficiency awards, for a total award of $19.1 million. As indicated above, on September 15, 2016, the CPUC approved the settlement agreement. On October 7, 2016, the Utility submitted a supplemental shareholder incentive advice letter reflecting the approval by the CPUC of the settlement agreement and other minor modifications to its September 1, 2016 incentive award request. The advice letter requires CPUC approval in a resolution, which the Utility anticipates receiving during the fourth quarter of 2016.

**Utility-Owned PV Generation Cost Savings Incentive Award**

In April 2010, the CPUC authorized the Utility to develop, own, and operate PV facilities and established a cost savings incentive mechanism which states that shareholders are eligible to retain ten percent of the difference between the actual average cost per unit and the threshold set by the CPUC. From 2011 - 2013, the Utility constructed nine PV projects with a total capacity of 150 MW and the weighted average unit capital cost came in below the CPUC specified threshold. In July 2016, the CPUC approved the recovery of $16 million in shareholder incentives related to these projects under the PV capital cost savings incentive mechanism.

## LEGISLATIVE AND REGULATORY INITIATIVES

The California Legislature and the CPUC have adopted requirements, policies and decisions to improve and refine gas and electric safety citation programs, accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles, promote customer energy efficiency and demand response programs, and implement new state law requirements applicable to natural gas storage facilities. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. Significant developments that have occurred since the 2015 Form 10-K was filed with the SEC are discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

*Electric Distribution Resources Plan*

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of DERs. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service.

In August 2016, as part of the CPUC's consideration of the Utility's electric distribution resources plan, hearings were held on field demonstration projects proposed by the Utility to test various distribution-related services that DERs might provide to the Utility. A CPUC decision is expected later this year on the field demonstration projects.

Additionally, on August 22, 2016, the Utility filed comments generally supporting a CPUC ruling proposing a revised scope and schedule for the proceeding. At this time, it is uncertain when a final CPUC decision approving, disapproving or modifying the Utility's electric distribution resources plan will be issued.

*Integrated Distributed Energy Resources - Regulatory Incentives Pilot Program*

On April 4, 2016, the assigned CPUC commissioner and ALJ issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective DERs. The ruling assumes that the incentive would take the form of an additional payment to the Utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The exact figure would be determined later if the proposal or a similar alternative is adopted by the CPUC. The ruling also states that it does not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities.

On May 9 and May 23, 2016, the Utility, two other California utilities (the "Joint Utilities") and other parties filed their comments. The Joint Utilities indicate that providing a regulatory incentive to utilities to deploy DERs in place of distribution investment is premature until the operating and performance characteristics of DERs are better understood and evaluated as part of pilot projects. The Joint Utilities instead propose initiating DER pilots that would advance understanding of distribution deferral and DER procurement processes.

On September 1, 2016, the assigned CPUC commissioner and ALJ issued an amended scoping memo and ruling that re-categorized all activities in the proceeding as rate-setting, consolidated remaining issues into one phase, and proposed a revised regulatory incentive pilot to test how an earnings opportunity affects DER sourcing. On September 15 and September 22, 2016, the Joint Utilities and other parties filed comments on the revised regulatory incentive pilot. The Joint Utilities support piloting different earnings mechanisms to better compare advantages and disadvantages of different alternatives and repeated their recommendation that the CPUC enable a broader dialogue on utility compensation mechanisms, rather than narrowly focusing on regulatory incentives for DER deployment. A proposed CPUC decision is expected later this year.

*Electric Rate Reform and Net Energy Metering*

On July 3, 2015, the CPUC approved a final decision to authorize the California IOUs to gradually flatten their tiered residential electric rate structures from four tiers to two tiers by January 1, 2019. The decision approved higher minimum bill charges for residential customers and also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential electric customers based on time-of-use rates (known as "default time-of-use rates") unless customers elect otherwise. The Utility also may propose to impose a fixed charge on residential electric customers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge in electric rates.

In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates are expected to become effective for new NEM customers later in 2016, when the Utility is expected to reach its current NEM cap. The CPUC indicated that it may revisit the NEM successor tariff in 2019. After the current NEM cap is reached, new NEM customers will be required to pay an interconnection fee, will be charged for energy use on time-of-use rates, and will be required to pay non-bypassable charges to help fund some of the costs of low-income, energy efficiency, and other programs that other customers pay. Unlike the initial NEM tariff, there is no cap on the total capacity of distributed generation that can be installed under the new rules. On March 7, 2016, the Utility and certain other parties, including TURN and CUE, filed applications for rehearing. The Utility requested that the CPUC vacate its January 2016 decision that the Utility asserts contains legal and factual errors. Many parties argued that the CPUC failed to complete its duties under AB 327, which required the CPUC to evaluate the costs and benefits of NEM. On September 15, 2016, the CPUC voted to deny the applications for rehearing, concluding that good cause had not been established to grant a rehearing and that the NEM decision adopted a successor tariff as required.

*Electric Vehicle (EV) Infrastructure Development*

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain more than 25,000 EV charging stations and the associated infrastructure. The Utility proposed to engage with third-party EV service providers to operate and maintain the charging stations. The Utility requested that the CPUC approve forecasted capital expenditures of $551 million over the five-year deployment period.

On September 4, 2015, the assigned CPUC commissioner and the ALJ issued a scoping memo and procedural schedule that required the Utility to supplement its application by submitting a more phased deployment approach that will be considered in a first phase of the proceeding. On October 12, 2015, the Utility submitted supplemental testimony presenting two separate proposals, with the first proposal including capital expenditures of $70 million for approximately 2,500 charging stations and the second proposal comprising $187 million for approximately 7,500 charging stations.

After discussions with a number of parties about the two proposals, the Utility filed with the CPUC a settlement agreement on March 21, 2016 that it entered into with environmental advocates, automakers, electric vehicle drivers, labor, and environmental justice advocates, to deploy about 7,500 charging stations over three years with forecasted capital expenditures of $132 million. (TURN, ORA, and certain equipment suppliers are not parties to the settlement agreementand filed responses on April 12, 2016, generally opposing the settlement agreement.) The settlement agreement is subject to approval by the CPUC. Hearings were held in April 2016 and a proposed decision for the first phase of the proceeding is expected to be issued in the fourth quarter of 2016. Further deployment of EV charging stations would be considered in a second phase of the proceeding depending on the outcome of the first phase.

**ENVIRONMENTAL MATTERS**

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes, such as groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations; the reporting and reduction of carbon dioxide and other greenhouse gas emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements, as well as "Item 1A. Risk Factors" and Note 13 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K.)

**CONTRACTUAL COMMITMENTS**

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that relate to purchases of electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and purchases of fuel and transportation to support the Utility's generation activities. (See "Purchase Commitments" in Note 9 of the Notes to the Condensed Consolidated Financial Statements). Contractual commitments that relate to financing arrangements include long-term debt, preferred stock, and certain forms of regulatory financing. For more in-depth discussion about PG&E Corporation's and the Utility's contractual commitments, see "Liquidity and Financial Resources" above and Management's Discussion and Analysis of Financial Condition and Results of Operations - Contractual Commitments in the 2015 Form 10-K.

**Off-Balance Sheet Arrangements**

PG&E Corporation and the Utility do not have anyoff-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K (the Utility's commodity purchase agreements).

## RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances and offset credits, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. These activities arediscussed in detail in the 2015 Form 10-K. There were no significant developments to the Utility's and PG&E Corporation's risk management activities during the nine months ended September 30, 2016.

## CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, asset retirement obligations, and pension and other postretirement benefits plans to be critical accounting policies. These policies are considered critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates. These accounting policies and their key characteristics are discussed in detail in the 2015Form 10-K.

## ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See the discussion above in Note 2 of the Notes to the Condensed Consolidated Financial Statements.

**FORWARD-LOOKING STATEMENTS**

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the final phase two CPUC decision in the 2015 GT&S rate case, the 2017 GRC, the TO rate cases, and other ratemaking and regulatory proceedings;

- the timing and outcomes of the debarment proceeding and potential remedial and other measures that may be imposed on the Utility as a result of the debarment proceeding and the jury's verdict in the federal criminal trial of the Utility (including a potential appointment of one or more independent third-party monitor(s)), the Utility's motion for judgment of acquittal, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, including the U.S. Attorney's Office investigation in connection with the natural gas explosion that occurred in Carmel, California on March 3, 2014 and the U.S. Attorney's Office in San Francisco investigation in connection with matters relating to the federal criminal trial discussed above, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the timing and outcomes of the CPUC's investigation of communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, and of the U.S. Attorney's Office in San Francisco and the California Attorney General's office investigations in connection with communications between the Utility's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in the Utility's ratemaking proceedings;

- the timing and outcomes of the Butte fire litigation, and whether the Utility's insurance is sufficient to cover the Utility's liability resulting therefrom or whether insurance is otherwise available; and whether additional investigations and proceedings in connection with the Butte fire will be opened;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the jury's verdict in the federal criminal trial and a possible conviction of the Utility, the state and federal investigations of natural gas incidents, matters relating to the criminal federal trial, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- whether the Utility can control its costs within the authorized levels of spending, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;

- the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

- the outcomes of the SED's investigations of potential violations identified though audits, investigations, or self-reports, including in connection with the Utility's September 2016 self-report related to atmospheric corrosion inspections;

- the outcome of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities, inspection and maintenance practices, customer billing and privacy, and physical and cyber security, environmental laws and regulations;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon; whether the CPUC approves the joint proposal that will phase out the Utility's Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether the Utility obtains the approvals required to withdraw its NRC application to renew the two Diablo Canyon operating licenses; whether the State Lands Commission could be required to perform an environmental review of the new lands lease as a result of the WBA assertion that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act; and whether the Utility will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;

- whether the Utility is successful in ensuring physical security of its critical assets and whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility and its third party vendors and contractors (who host, maintain, modify and update some of the Utility's systems) are able to protect the Utility's operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's information technology and operating systems;

- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and sufficient to cover the Utility's liability;

- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, electric vehicles, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;

- whether the Utility's climate change adaptation strategies are successful;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the jury's verdict in the federal criminal trial of the Utility and its possible conviction, and other enforcement matters affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see "Risk Factors" in the 2015 Form 10-K and in " Item. 1A. Risk Factors" below. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. (See the section above entitled "Risk Management Activities" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.)

## ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of September 30, 2016, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended September 30, 2016, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

## PART II. OTHER INFORMATION

### ITEM 1. LEGAL PROCEEDINGS

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 9 of the Notes to the Condensed Consolidated Financial Statement and Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, "Enforcement and Litigation Matters."

**Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission**

For a description of this matter, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K, the discussion of the Penalty Decision in Note 13 of the Notes to the Consolidated Financial Statements inthe 2015 Form 10-K, and the discussion included in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

**Federal Criminal Trial**

On June 14, 2016, a federal criminal trial against the Utility began in the United States District Court for the Northern District of California, in San Francisco, on 12 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility illegally obstructed the NTSB investigation into the cause of the San Bruno accident. On July 26, 2016, the court granted the government's motion to dismiss Count 13 alleging that the Utility knowingly and willfully failed to retain a strength test pressure record with respect to a distribution feeder main, thereby reducing the total number of counts from 13 to 12.

On August 2, 2016, the remaining Alternative Fines Act sentencing allegations in the case were dismissed. The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." (The remaining allegations related to $281 million of gross gains that the government alleged the Utility derived. As previously disclosed, in December 2015, the court dismissed the government's allegations regarding the amount of losses.)

On August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act.

On August 16, 2016, the Utility filed a motion under Federal Rule of Criminal Procedure 29 for a judgment of acquittal, arguing that the evidence was insufficient to sustain a conviction for the six counts on which the jury returned a guilty verdict. The court indicated that it will decide on this motion based on briefs filed by the parties, without oral argument. The Utility is not able to predict when the court will decide on the motion. A sentencing hearing is currently scheduled for January 23, 2017.

For description of this matter, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K, the section entitled "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 in the 2015 Form 10-K, and the section entitled "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

**Litigation Related to the San Bruno Accident and Natural Gas Spending**

As of September 30, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the *San Bruno Fire Derivative Cases* and are pending in the Superior Court of California, County of San Mateo.&bbsp;The remaining three cases are *Tellardin v. PG&E Corp. et al.,Iron Workers Mid-South Pension Fund v. Johns, et al.,* and *Bushkin v. Rambo et al.*

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated *San Bruno Fire Derivative Cases* pending conclusion of the federal criminal proceedings against the Utility. On September 16, 2016, the San Mateo Superior Court requested that all counsel appear for a status conference in the consolidated matter. The date of the conference has been set for November 16, 2016.

*Bushkin v. Rambo et al*., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit *Iron Workers Mid-South Pension Fund v. Johns, et al.*, discussed below. The plaintiff in the *Bushkin* lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the *Bushkin* plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the Court to dismiss plaintiff's petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation's motion, and indicated that plaintiff's petition was stayed pending resolution of the criminal matter against the Utility.

The *Iron Workers* action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the *San Bruno Fire Derivative Cases*. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court's request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the *San Bruno Fire Derivative Cases*. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the stay pending the resolution of the criminal proceedings against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017.

A case management conference in the action entitled *Tellardin v. PG&E Corp. et al.,* also pending in the Superior Court of California, San Mateo County, had been scheduled for August 9, 2016. On July 19, 2016, plaintiff requested that the court vacate the August 9, 2016 conference because, pursuant to the parties' agreement, defendants are not required to respond to the complaint in this action until 30 days after an order lifting the stay in the *San Bruno Fire Derivative Cases*. On August 2, 2016, the court vacated the August 9, 2016 conference.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

For additional information regarding these matters, see the discussion entitled "Enforcement and Litigation Matters" above in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations. In addition, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Butte Fire Litigation**

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, and destroyed 549 homes, 368 outbuildings and four commercial properties. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of September 30, 2016, approximately 50 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,850 individual plaintiffs representing approximately 800 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling preference cases (presented by individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling). The Utility also has begun scheduling mediation of other cases. Case management conferences were held on July 14, 2016 and September 1, 2016. The next case management conference is scheduled for December 1, 2016.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes it was not negligent; however, there can be no assurance that a court or a jury would agree with the Utility.

For more information regarding the Butte fire, see Note 9 "Contingencies and Commitments" of the Notes to the Condensed Consolidated Financial Statements.

**Other Enforcement Matters**

Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, investigations that were commenced after a pipeline explosion in Carmel, California on March 3, 2014, and other enforcement matters. See the discussion entitled "Enforcement and Litigation Matters" above in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Diablo Canyon Nuclear Power Plant**

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. The Utility expects that its decision to retire Diablo Canyon will affect the terms of the final settlement agreementbetween the Utility, the Central Coast Water Board and the California Attorney General's Office. Also, as required under the California State Water Resources Control Board's Once-Through Cooling Water Policy, beginning in 2016, the Utility will pay an annual interim mitigation fee until operations cease at the end of the current licenses.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on the Utility's financial condition or results of operations.

For more information regarding the 2003 settlement agreement between the Central Coast Water Board, the Utility, and the California Attorney General's Office, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Venting Incidents in San Benito County**

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called "pigs" that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline must be released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility's transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County District Attorney notified the Utility in December 2014 that it was contemplating bringing a civil legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. On October 28, 2015, the district attorney informed the Utility that it would seek civil penalties in excess of $100,000 but is willing to continue to explore settlement options with the Utility. The Utility remains in settlement discussions with the district attorney's office.

For more information, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

**Transformer Oil Release in Sonoma County**

During a rain storm in February 2015, transformer oil was released into an underground vault in the City of Santa Rosa, in Sonoma County, while a Utility crew was replacing a broken transformer. Following further rains, the oil released from the vault and reached a nearby creek. The event was investigated by Santa Rosa Fire Department, the local environmental enforcement authority, and later referred to the Sonoma County District Attorney's Office. In May 2016, the District Attorney informed the Utility that it would seek penalties and costs in excess of $100,000 for alleged violations of several sections of the California Health and Safety and California Government codes which prohibit unauthorized spills or releases of oil into waters of the state and require that releases be reported to the Office of Emergency Services. The Utility is in the process of settlement negotiations with the Sonoma County District Attorney's Office.

## ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see the section of the 2015 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Forward-Looking Statements."

***PG&E Corporation and the Utility may incur material liability in connection with the Butte fire.***

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to the Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, and destroyed 549 homes, 368 outbuildings and four commercial properties. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of September 30, 2016, approximately 50 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador involving approximately 1,850 individual plaintiffs representing approximately 800 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

In connection with this matter, the Utility may be liable for property damages, interest and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent.

The process for estimating costs associated with claims relating to the Butte fire, including for estimated property damages, requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including discoveries from the plaintiffs and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may change. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition and the results of operations during the period such change occurred.

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals during such reporting periods.

***PG&E Corporation's and the Utility's future financial results could be materially affected by the jury's verdict in the federal criminal trial and possible judgment of conviction of the Utility, the debarment proceeding and an increased number of government investigations and requests for information.***

As previously disclosed, on August 9, 2016, the jury returned its verdict in the federal criminal trial against the Utility on 11 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility illegally obstructed the NTSB investigation into the cause of the San Bruno accident. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include obstructing a federal agency proceeding and violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On August 16, 2016, the Utility filed a motion under Federal Criminal Procedure 29 for a judgment of acquittal, arguing that the evidence was insufficient to sustain a conviction for the six counts on which the jury returned a guilty verdict.

In September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the SanBruno explosion and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation.

As a result of the August 9, 2016 jury's verdict in the federal criminal trial, the Utility updated its registration on the federal government's System for Award Management (SAM), a federal procurement database, to reflect the verdict. Under federal law, the government may not enter into a contract with any corporation that was convicted of a felony criminal violation under any federal law within the preceding 24 months, where the awarding agency is aware of the conviction, unless an agency has considered suspension or debarment of the corporation and made a determination that this action is not necessary to protect the interests of the government. Following the update of the SAM, the Utility and the DOI have been in discussions regarding such a determination and regarding a possible interim administrative agreement that would allow the federal government agencies to contract with the Utility while the DOI is completing its debarment inquiry. It is uncertain when and if the Utility and the DOI will enter into an interim administrative agreement. It is also uncertain when or if further action will be taken by the DOI. The DOI debarment inquiry could result in the Utility's suspension or debarment from future federal government contracts for a fixed, specified time period or entering into an administrative agreement with the DOI to resolve debarment matters.

As a result of the DOI inquiry and/or of the August 9, 2016 jury's guilty verdict on six felony counts in the federal criminal trial, the Utility may be required to implement remedial and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third party monitor(s). If appointed, the Utility expects a monitor or monitors would serve for a period of time and report periodically to the court or a department or agency of the government.

The jury's verdict, a possible judgment of conviction of the Utility and the outcome of the debarment proceeding could harm the Utility's relationships with regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, they could negatively affect the outcome of future ratemaking and regulatory proceedings, for example by, enabling parties to argue that the Utility should not be allowed to recover costs that the parties allege are somehow related to the criminal charges on which the Utility was found guilty. They could also result in increased regulatory or legislative scrutiny with respect to various aspects of how the Utility's business is conducted or organized. As discussed under the heading "Regulatory Matters" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, the SED continues evaluating PG&E Corporation's and the Utility's organizational culture and governance in the CPUC's pending investigation to examine the Utility's safety culture. The Utility also could incur material costs, not recoverable through rates, to implement remedial and other measures that could be imposed.

The Utility is also a target of an increased number of investigations and government requests for information. As previously disclosed, the U.S. Attorney's Office is investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the criminal trial discussed above. The U.S. Attorney's Office in San Francisco and the California Attorney General's office also are investigating matters related to allegedly improper communication between the Utility and CPUC personnel. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The Utility was also recently contacted by certain other federal agencies with requests for information. While the Utility believes that these requests for information are routine, theiroutcome is uncertain. The Utility also is unable to predict the outcome of pending investigations, including whether any charges will be brought against the Utility. Any charges that could be brought against the Utility or proceedings that could result from the current and future government investigations and requests for information could result in material costs to PG&E Corporation and the Utility.

The Utility’s conviction, the outcome of the debarment proceeding and any proceedings that could result from the current and future government investigations and requests for information could harm its relationships with regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, they could negatively affect the outcome of future ratemaking and regulatory proceedings, for example, by enabling parties to argue that the Utility should not be allowed to recover costs that the parties allege are somehow related to the criminal charges on which the Utility was found guilty.

They could also result in increased regulatory or legislative scrutiny with respect to various aspects of how the Utility’s business is conducted or organized. As discussed under the heading “Regulatory Matters” in Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, the SED continues evaluating PG&E Corporation’s and the Utility’s organizational structure in the CPUC’s pending investigation to examine the Utility’s safety culture.

***The Utility’s insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event, or may not become available at a reasonable cost, or available at all.***

The Utility’s ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond the Utility’s control. (See “Risks Related to Operations and Information Technology” in Item 1A Risk Factors of the 2015 Form 10-K.) Current insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. (In particular, the Utility may incur material liability in connection with the Butte fire. See “PG&E Corporation and the Utility may incur material liability in connection with the Butte fire” above.)

In addition, California law includes a doctrine of inverse condemnation that is routinely invoked in California for wildfire damages. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages and takings as a result of the design, construction and maintenance of utility facilities, including its electric transmission lines. As a result of the strict liability standard applied to wildfires, recent losses recorded by insurance companies, the risk of increase of wildfires including as a result of the ongoing drought, and the Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at comparable cost and terms as the Utility’s current insurance coverage, or at all. In addition, the Utility is unable to predict whether it would be allowed to recover in rates the increased costs of insurance or the costs of any uninsured losses.

If the amount of insurance is insufficient or otherwise unavailable, or if the Utility is unable to recover in rates the costs of any uninsured losses, PG&E Corporation’s and the Utility’s financial condition, results of operations, or cash flows could be materially affected.

***The Utility’s operational and information technology systems could fail to function properly or be improperly accessed or damaged by third parties (including cyberand physical attacks) or damaged by severe weather, natural disasters, or other events. Any of these events could disrupt the Utility’s operations and cause the Utility to incur unanticipated losses and expense or liability.***

The operation of the Utility’s extensive electricity and natural gas systems relies on evolving and increasingly complex operational and information technology systems and network infrastructures that are interconnected with the systems and network infrastructure owned by third parties. All of the Utility’s operational and technology systems and network infrastructure are vulnerable to disability or failures in the event of cyber and physical attacks. Cyberattacks are increasingly sophisticated and may include computer hacking, viruses, malware, social engineering, denial of service attacks, ransomware, destructive malware, or other means of disruption, destruction, or unauthorized access, acquisition or control. In addition, hardware, software, or applications the Utility develops or procures from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information security. Physical attacks may include acts of sabotage, acts of war, acts of terrorism, or other physical acts. The Utility’s operational and information technology systems and networks are deemed critical infrastructure, and any failure or decrease in their functionality could, among other things, cause harm to the public or employees, significantly disrupt operations,negatively impact the Utility’s ability to generate, transport, deliver and store energy and gas, or otherwise operate in the most efficient manner or at all, undermine the Utility’s performance of critical business functions, damage the Utility’s assets or operations or those of third parties, and lead to reputational harm. As a result, such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, investigations, and regulatory actions that could result in fines and penalties, and loss of customers, any of which could have a material effect on PG&E Corporation’s and the Utility’s financial condition and results of operations.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require ongoing maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. The Utility often relies on third-party vendors to host, maintain, modify, and update its systems and these third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience internal or external security incidents. Any incidents, disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification of existing systems or implementation of new systems could result in increased costs, the inability to track or collect revenues, or diversion of management's and employees' attention and resources, or negatively affect the Utility's ability to maintain effective financial controls or timely file required regulatory reports. The Utility also could be subject to patent infringement claims arising from the use of third-party technology by the Utility or by a third-party vendor.

In addition, the Utility's information systems contain confidential information, including information about customers and employees. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject the Utility to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm the Utility's reputation.

The Utility and its third party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to the Utility's information technology systems, or confidential data, or to disrupt the Utility's operations. None of these attempts or breaches has individually or in the aggregate resulted in a security incident with a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent the unauthorized access to its systems, infrastructure, or data, or the disruption of its operations, either of which could materially affect PG&E Corporation's and the Utility's financial condition and results of operations.

While the Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents, there is no guarantee that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.

***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire.***

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial results. In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 13 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K.)

On June 20, 2016, the Utility entered into a proposal to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025, subject to certain regulatory approvals. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before the licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial results.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See "Regulatory Environment" in Item 1. Business in the 2015 Form 10-K.) If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon before the licenses expire in 2024 and 2025. At September 30, 2016, the Utility's unrecovered investment in Diablo Canyon was $1.7 billion.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. If the Utility obtains contingent approvals referred to herein that will result in retiring Diablo Canyon at the end of the current NRC operating licenses, the Utility will not be required to install cooling towers or implement alternative measures in order to comply with the California State Water Board Once-Through Cooling Water Policy, thus eliminating the risk of regulatory uncertainty regarding the measures that could have been imposed on the Utility or of incurring a material charge related thereto. Even if the Utility is ultimately not required to install cooling towers, under the State Water Board's interim mitigation measures applicable to Diablo Canyon's operations prior to 2025, starting in 2016, it will be required to make payments to the California Coastal Conservancy to fund various environmental mitigation projects, that the Utility does not expect to exceed$5 million per year.

On June 28, 2016 the California State Lands Commission approved an extension of the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon, to run concurrently with Diablo Canyon's current operating licenses. The Utility will be required to obtain an additional lease extension from the State Lands Commission to cover the period of time necessary to decommission the facility. The State Lands Commission and California Coastal Commission will evaluate appropriate environmental mitigation and development conditions associated with the decommissioning project, the costs of which could be substantial.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2 of the Notes to Condensed Consolidated Financial Statements in Item 1 herein and Note 2 of the Notes to the Consolidated Financial Statement in Item 8 of the 2015 Form 10-K.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial results could be materially affected.

## ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the quarter ended September 30, 2016, PG&E Corporation made equity contributions totaling $460 million to the Utility in order to maintain the 52% common equity component of the Utility's CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended September 30, 2016.

**Issuer Purchases of Equity Securities**

During the quarter endedSeptember 30, 2016, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended September 30, 2016, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

## ITEM 5. OTHER INFORMATION

**Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends**

The Utility's earnings to fixed charges ratio for the nine months ended September 30, 2016 was 1.57. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2016 was1.55. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement No. 333-193879.

PG&E Corporation's earnings to fixed charges ratio for the nine months ended September 30, 2016 was 1.55. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-193880.

## ITEM 6. EXHIBITS

| | |
|---|---|
| 3.1 | Bylaws of PG&E Corporation amended as of September 20, 2016 |
| 3.2 | Bylaws of Pacific Gas and Electric Company amended as of September 20, 2016 |
| *10.1 | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and David S. Thomason dated August 8, 2016 |
| *10.2 | Performance Share Award Agreement subject to financial goals between David S. Thomason and PG&E Corporation dated August 8, 2016 |
| *10.3 | Performance Share Award Agreement subject to safety and customer affordability goals between David S. Thomason and PG&E Corporation dated August 8, 2016 |
| 12.1 | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 31.1 | Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certifications of the Principal Executive Officers and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| **32.1 | Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| **32.2 | Certifications of the Principal Executive Officers and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

*Management contract or compensatory agreement.
**Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

/s/ JASON P. WELLS

Jason P. Wells
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

/s/ DAVID S. THOMASON

David S. Thomason
Vice President, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: November 4, 2016

**EXHIBIT INDEX**

| | |
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*Management contract or compensatory agreement.
**Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

# Exhibit 10

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K
**CURRENT REPORT**
**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**Date of Report:**
**September 15, 2015**
(Date of earliest event reported)

# PG&E CORPORATION
(Exact Name of Registrant as specified in Charter)

| **California** | **1-12609** | **94-3234914** |
|---|---|---|
| (State or other jurisdiction of incorporation) | (Commission File Number) | (IRS Employer Identification No.) |

| **77 Beale Street, P. O. Box 770000, San Francisco, California** | **94105** |
|---|---|
| (Address of principal executive offices) | (Zip code) |

**415-267-7000**
(Registrant's Telephone Number, Including Area Code)

**N/A**
(Former Name or Former Address, if Changed Since Last Report)

# PACIFIC GAS AND ELECTRIC COMPANY
(Exact Name of Registrant as specified in Charter)

| **California** | **1-2348** | **94-0742640** |
|---|---|---|
| (State or other jurisdiction of incorporation) | (Commission File Number) | (IRS Employer Identification No.) |

| **77 Beale Street, P. O. Box 770000, San Francisco, California** | **94177** |
|---|---|
| (Address of principal executive offices) | (Zip code) |

**(415) 973-7000**
(Registrant's Telephone Number, Including Area Code)

**N/A**
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting Material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

**Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.**

***Amendment of Officer and Director Grantor Trust Agreements***

On September 15, 2015, PG&E Corporation approved the amendment and restatement of the PG&E Corporation Director Grantor Trust Agreement and the PG&E Corporation Officer Grantor Trust Agreement (together, the "Trust Agreements") that were established in 1998. These irrevocable trusts fund certain benefits payable under a number of plans sponsored by PG&E Corporation and its subsidiary, Pacific Gas and Electric Company ("Utility"), that provide non-tax-qualified benefits (such as deferred compensation) to officers, certain employees, and non-employee directors. The Trust Agreements, including the recent amendments, are designed to, among other things, protect participants against the risk that obligations to them will not be paid; however, the assets of the trusts remain assets of PG&E Corporation that are within the reach of PG&E Corporation's creditors if the company becomes insolvent or bankrupt. The amendments to the Trust Agreements are intended to better align the Trust Agreements with current market practice and PG&E Corporation's and the Utility's plans, and include: (1) adding the PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors and the PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan to the list of non-tax-qualified benefit plans whose benefits are covered by the trusts' assets, and (2) adopting a new definition of "potential change in control" and amending the existing definition of "change in control" so that they are consistent with the same definitions found in the PG&E Corporation 2012 Officer Severance Policy and the PG&E Corporation 2014 Long-Term Incentive Plan, which previously have been filed with the Securities and Exchange Commission.

The amended and restated Trust Agreements are expected to become effective on October 1, 2015, following their execution by PG&E Corporation and the trustee, Wells Fargo Bank, National Association.

**Item 8.01. Other Events.**

***Investigation of Butte Fire***

The California Department of Forestry and Fire Protection (Cal Fire) is investigating the source of the Butte Fire, a wildfire currently active in Amador and Calaveras Counties in Northern California, and whether a live tree may have contacted a power line owned and operated by the Utility, in the vicinity of the ignition point. The exact cause of the Butte Fire is unknown at this point, and the Utility is cooperating fully with Cal Fire's investigation of the cause of the Butte Fire. On September 18, 2015, Cal Fire reported that as a result of the fire, which is 60% contained, there were two deaths and approximately 365 residences and 261 outbuildings were destroyed and 26 other structures were damaged.

It is currently unknown whether the Utility would have any liability associated with the Butte Fire, but if it does, the Utility believes that based upon information currently available, it has sufficient insurance coverage for potential losses that may result from the Butte Fire. If insurance recoveries are unavailable or insufficient to cover such losses, PG&E Corporation's and the Utility's financial condition or results of operations could be materially adversely affected.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned hereunto duly authorized.

**PG&E CORPORATION**

Dated: September 18, 2015

By: LINDA Y.H. CHENG

LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: September 18, 2015

By: LINDA Y.H. CHENG

LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

# Exhibit 11

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

# FORM 8-K

**CURRENT REPORT**

**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**Date of Report: May 30, 2017**
(Date of earliest event reported)

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company
**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company:
PG&E Corporation ☐
Pacific Gas and Electric Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

PG&E Corporation ☐
Pacific Gas and Electric Company ☐

**Item 5.07 Submission of Matters to a Vote of Security Holders.**

On May 30, 2017, PG&E Corporation and its subsidiary, Pacific Gas and Electric Company (the "Utility"), held their joint annual meeting of shareholders.

***PG&E Corporation:***

At the joint annual meeting, the shareholders of PG&E Corporation voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in the joint proxy statement of PG&E Corporation and the Utility, filed with the Securities and Exchange Commission on April 18, 2017 (the "proxy statement"):

| | For | Against | Abstain | Broker Non-Vote (1) |
|---|---|---|---|---|
| Lewis Chew | 389,417,254 | 1,157,454 | 457,136 | 45,275,618 |
| Anthony F. Earley, Jr. | 386,404,173 | 4,186,246 | 441,425 | 45,275,618 |
| Fred J. Fowler | 389,087,005 | 1,482,418 | 462,421 | 45,275,618 |
| Jeh C. Johnson | 389,363,549 | 906,300 | 761,995 | 45,275,618 |
| Richard C. Kelly | 387,012,778 | 2,012,268 | 2,006,798 | 45,275,618 |
| Roger H. Kimmel | 389,383,341 | 1,155,904 | 492,599 | 45,275,618 |
| Richard A. Meserve | 386,598,444 | 3,957,007 | 476,393 | 45,275,618 |
| Forrest E. Miller | 387,234,546 | 3,312,361 | 484,937 | 45,275,618 |
| Eric D. Mullins | 389,508,536 | 1,027,134 | 496,174 | 45,275,618 |
| Rosendo G. Parra | 389,107,608 | 1,439,465 | 484,771 | 45,275,618 |
| Barbara L. Rambo | 387,048,814 | 3,481,399 | 501,631 | 45,275,618 |
| Anne Shen Smith | 389,843,077 | 681,995 | 506,772 | 45,275,618 |
| Geisha J. Williams | 389,738,362 | 802,464 | 491,018 | 45,275,618 |

(1) A broker non-vote occurs when shares held by a broker for a beneficial owner are not voted because (i) the broker did not receive voting instructions from the beneficial owner, and (ii) the broker lacked discretionary authority to vote the shares. Broker non-votes are counted when determining whether the necessary quorum of shareholders is present or represented at each annual meeting.

Each director nominee named above was elected a director of PG&E Corporation.

2. Ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm for 2017 (included as Item 2 in the proxy statement):

| | |
|---|---|
| **For:** | 426,606,390 |
| **Against:** | 8,978,888 |
| **Abstain:** | 722,184 |

This proposal was approved.

3. Non-binding advisory vote to approve the company's executive compensation (included as Item 3 in the proxy statement):

| | |
|---|---|
| **For:** | 373,309,901 |
| **Against:** | 16,573,399 |
| **Abstain:** | 1,148,544 |
| **Broker Non-Vote (1)** | 45,275,618 |

(1) See footnote 1 above.

This proposal was approved.

4. Non-binding advisory vote to approve the frequency of the company's shareholder advisory vote on executive compensation (included as Item 4 in the proxy statement):

| | |
|---|---|
| **1 year:** | 353,094,188 |
| **2 years:** | 516,815 |
| **3 years:** | 36,745,375 |
| **Abstain:** | 675,466 |
| **Broker Non-Vote** (1) | 45,275,618 |

(1) See footnote 1 above.

The one-year option was approved.

On May 31, 2017, in accordance with the voting results for this item, the Board of Directors of PG&E Corporation determined that the company will continue providing shareholders with an annual opportunity to cast a non-binding advisory vote on executive compensation until the next required advisory vote on the frequency of future advisory votes on executive compensation. Under the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), PG&E Corporation is required to provide shareholders at least once every six calendar years with the opportunity to cast a non-binding advisory vote on the frequency of shareholder votes on executive compensation.

5. Shareholder proposal regarding customer approval of the charitable giving program (included as Item 5 in the proxy statement):

| | |
|---|---|
| **For:** | 12,393,555 |
| **Against:** | 365,838,208 |
| **Abstain:** | 12,800,081 |
| **Broker Non-Vote** (1) | 45,275,618 |

(1) See footnote 1 above.

This proposal was not approved.

***Pacific Gas and Electric Company:***

At the joint annual meeting, the shareholders of Pacific Gas and Electric Company voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in the proxy statement):

| | **For** | **Against** | **Abstain** | **Broker Non-Vote** (1) |
|---|---|---|---|---|
| Lewis Chew | 266,692,205 | 175,709 | 135,252 | 5,728,486 |
| Anthony F. Earley, Jr. | 266,703,514 | 163,462 | 136,190 | 5,728,486 |
| Fred J. Fowler | 266,702,522 | 166,420 | 134,224 | 5,728,486 |
| Jeh C. Johnson | 266,674,558 | 111,585 | 217,023 | 5,728,486 |
| Richard C. Kelly | 266,785,089 | 84,423 | 133,654 | 5,728,486 |
| Roger H. Kimmel | 266,696,673 | 171,172 | 135,321 | 5,728,486 |
| Richard A. Meserve | 266,677,384 | 191,708 | 134,074 | 5,728,486 |
| Forrest E. Miller | 266,702,849 | 164,003 | 136,314 | 5,728,486 |
| Eric D. Mullins | 266,766,020 | 103,591 | 133,555 | 5,728,486 |
| Rosendo G. Parra | 266,693,928 | 172,633 | 136,605 | 5,728,486 |
| Barbara L. Rambo | 266,708,691 | 162,384 | 132,091 | 5,728,486 |
| Anne Shen Smith | 266,779,052 | 95,142 | 128,972 | 5,728,486 |
| Nickolas Stavropoulos | 266,791,882 | 77,156 | 134,128 | 5,728,486 |
| Geisha J. Williams | 266,788,050 | 83,516 | 131,600 | 5,728,486 |

(1) See footnote 1 above.

Each director nominee named above was elected a director of Pacific Gas and Electric Company.

2. Ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm for 2017 (included as Item 2 in the proxy statement):

| | |
|---|---|
| **For:** | 272,243,238 |
| **Against:** | 177,239 |
| **Abstain:** | 311,175 |

This proposal was approved.

3. Non-binding advisory vote to approve the company's executive compensation (included as Item 3 in the proxy statement):

| | |
|---|---|
| **For:** | 266,508,633 |
| **Against:** | 303,549 |
| **Abstain:** | 190,984 |
| **Broker Non-Vote** (1) | 5,728,486 |

(1) See footnote 1 above.

This proposal was approved.

4. Non-binding advisory vote to approve the frequency of the company's shareholder advisory vote on executive compensation (included as Item 4 in the proxy statement):

| | |
|---|---|
| **1 year:** | 266,708,668 |
| **2 years:** | 94,439 |
| **3 years:** | 87,237 |
| **Abstain:** | 112,822 |
| **Broker Non-Vote** (1) | 5,728,486 |

(1) See footnote 1 above.

The one-year option was approved.

On May 31, 2017, in accordance with the voting results for this item, the Board of Directors of Pacific Gas and Electric Company determined that the company will continue providing shareholders with an annual opportunity to cast a non-binding advisory vote on executive compensation until the next required advisory vote on the frequency of future advisory votes on executive compensation. Under the Dodd-Frank Act, Pacific Gas and Electric Company is required to provide shareholders at least once every six calendar years with the opportunity to cast a non-binding advisory vote on the frequency of shareholder votes on executive compensation.

**Item 8.01 Other Events.**

*Common Stock Cash Dividend Increase*

On May 31, 2017, the Board of Directors of PG&E Corporation approved a new annual common stock cash dividend of $2.12 per share ($0.53 per share quarterly), an increase from the current annual cash dividend of $1.96 per share ($0.49 per share quarterly), and the Board of Directors of the Utility approved a new annual common stock cash dividend of $1.08 billion ($270 million quarterly), an increase from the current annual cash dividend of $976 million ($244 million quarterly).

Each of the Boards retains authority to change its annual dividend at any time, especially if unexpected events occur that would change the Board's views as to the prudent level of cash conservation.  No dividends are payable until after the respective Board of Directors of PG&E Corporation and the Utility declares a dividend.

*Common and Preferred Stock Cash Dividend Declarations*

On May 31, 2017, the Board of Directors of PG&E Corporation declared a cash dividend on PG&E Corporation's common stock for the second quarter of 2017 in the amount of $0.53 per share from PG&E Corporation's retained earnings, payable on July 15, 2017 to shareholders of record on June 30, 2017.

Also on May 31, 2017, the Board of Directors of the Utility declared a cash dividend on the Utility's common stock for the second quarter of 2017 in the aggregate amount of $270 million from the Utility's retained earnings, payable to PG&E Corporation no later than June 6, 2017. The Board of Directors of the Utility also declared the regular preferred stock dividend for the three-month period ending July 31, 2017, payable on August 15, 2017 to shareholders of record on July 31, 2017.

A copy of a press release related to matters discussed in this Current Report on Form 8-K is furnished as Exhibit 99.1 hereto.

**Item 9.01 Financial Statements and Exhibits.**

(d) Exhibits

The following exhibit is being furnished, and it is not deemed to be filed:

Exhibit 99.1    Press release dated May 31, 2017

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

**PG&E CORPORATION**

Dated: May 31, 2017

By: /s/ Linda Y.H. Cheng
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: May 31, 2017

By: /s/ Linda Y.H. Cheng
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

Exhibit Index

| | |
|---|---|
| Exhibit 99.1 | Press release dated May 31, 2017 |

PG&E Corporation

Corporate Relations | 77 Beale Street | San Francisco, CA 94105 | 1 (415) 973-5930

**May 31, 2017**

**PG&E Corporation Raises Common Stock Dividend, Shareholders Elect Former Secretary of Homeland Security Jeh C. Johnson to Boards of Directors**

**SAN FRANCISCO, Calif. –** PG&E Corporation (NYSE: PCG) today announced that it is raising its quarterly common stock dividend by 4 cents per share to 53 cents per share, beginning with the dividend for the second quarter of 2017. On an annual basis, this action increases PG&E Corporation's dividend by 8 percent, from $1.96 per share to $2 . 12 per share.

"This represents another significant step toward returning our dividend payout to levels in line with those of similar energy companies. Offering a comparable dividend positions PG&E to more cost-effectively raise capital to support continued major investments in safety, reliability and clean energy on behalf of our customers," said PG&E Corporation CEO and President Geisha Williams .

The company also announced that shareholders elected Williams to the PG&E Corporation Board of Directors, and elected former U.S. Secretary of Homeland Security Jeh C. Johnson to the PG&E Corporation Board of Directors and the Board of Directors of its subsidiary, Pacific Gas and Electric Company . Secretary Johnson will serve on the Compliance and Public Policy Committee and on the Nuclear, Operations, and Safety Committee of the PG&E Corporation Board of Directors.

"Our customers and our company stand to benefit greatly from Secretary Johnson's vast experience in the public and private sectors, particularly in matters of security, cybersecurity, critical infrastructure protection and emergency response," said PG&E Corporation Executive Chair of the Board Tony Earley .

Secretary Johnson served as the head of Homeland Security from December 2013 to January 2017, and is now a partner at the international law firm of Paul, Weiss, Rifkind, Wharton & Garrison LLP. Previously, he served as General Counsel of the U.S. Department of Defense, General Counsel of the U.S. Department of the Air Force, and Assistant U.S. Attorney in the Southern District of New York.

Both announcements reflect PG&E's continued focus on positioning itself for the future. Yesterday, in remarks at the joint annual shareholders meeting of PG&E Corporation and Pacific Gas and Electric Company, Williams highlighted the companies' progress on safety, reliability and reducing greenhouse gas emissions, among other accomplishments. She reaffirmed PG&E's commitment to safety and operational excellence, delivering for customers and leading the way to achieve California's clean energy goals.

"Ultimately, we see PG&E as not only playing a fundamental role in meeting our customers' evolving energy needs, but also paving the way for California's sustainable energy future. Our goals and plans over the next five years are focused on that….We are seeing exciting advancements in areas such as distributed generation, alternative-fueled vehicles and battery storage. Our job is to provide the platform that interconnects all of these technologies in order to maximize their benefits for customers," said Williams.

At the companies' joint annual meeting of shareholders , in addition to electing all nominees to the PG&E Corporation and Pacific Gas and Electric Company Boards of Directors, shareholders ratified the re-appointment of the companies' independent registered public accounting firm, Deloitte & Touche LLP; approved the companies' executive compensation on an advisory basis; approved an annual frequency for the advisory vote on executive compensation; and did not approve a shareholder proposal that PG&E Corporation discontinue its charitable giving program unless a majority of our customers positively affirm it through a public vote. Final voting results will be reported in a Current Report on Form 8-K to be filed with the Securities and Exchange Commission and will be available on the companies' websites.

**Dividend Payment and Record Dates**

The PG&E Corporation Board of Directors declared the second - quarter 2017 common stock dividend of $0.53 per share , payable on July 15, 2017 , to shareholders of record on June 30, 2017. In addition, the Pacific Gas and Electric Company Board of Directors declared the regular preferred stock dividend for the three-month period ending July 31, 2017, payable on August 15, 2017 to shareholders of record on July 31, 2017. Pacific Gas and Electric Company will pay dividends on its eight series of preferred stock as follows:

| First Preferred Stock, $25 Par Value | Quarterly Dividend to be Paid Per Share |
|---|---|
| **Redeemable** | |
| 5.00% | $0.31250 |
| 5.00% Series A | $0.31250 |
| 4.80% | $0.30000 |
| 4.50% | $0.28125 |
| 4.36% | $0.27250 |
| **Non-Redeemable** | |
| 6.00% | $0.37500 |
| 5.50% | $0.34375 |
| 5.00% | $0.31250 |

In order to be considered a shareholder of record for the common or preferred dividend payment, a shareholder must have purchased the stock at least three trading days before the applicable record date.

**Forward-Looking Statements**

This press release contains forward-looking statements regarding PG&E Corporation's goal to return its dividend payout to levels in line with those of similar energy companies, and its other goals and plans over the next five years, that are based on current expectations and assumptions which management believes are reasonable, and on information currently available to management, but are necessarily subject to various risks and uncertainties. In addition to the risk that these assumptions prove to be inaccurate, other factors that could cause actual results to differ materially from those contemplated by the forward-looking statements include: the outcome of the TO rate case, the cost of capital proceeding and other rate cases; the timing and outcome of the Butte fire litigation, whether Pacific Gas and Electric Company's (Utility) insurance is sufficient to cover the Utility's liability resulting therefrom, and whether insurance is otherwise available; the outcome of the safety culture proceeding pending at the California Public Utilities Commission; the Utility's ability to control its costs within the authorized levels of spending and the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs; the impact of the increasing cost of natural gas regulations; changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons; the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing for community choice aggregators; the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms; the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or interpretations, and the other factors disclosed in PG&E Corporation and the Utility's joint Annual Report on Form 10-K for the year ended December 31, 2016 and their joint Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 .

**About PG&E Corporation**

PG&E Corporation (NYSE: PCG) is a Fortune 200 energy-based holding company headquartered in San Francisco. It is the parent company of Pacific Gas and Electric Company, California's largest investor-owned utility. PG&E serves nearly 16 million Californians across a 70,000-square-mile service area in Northern and Central California. For more information, visit www.pgecorp.com and www.pge.com .

###

# Exhibit 12

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

# FORM 8-K

**CURRENT REPORT**

**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**Date of Report: October 13, 2017**
(Date of earliest event reported)

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company
**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 8.01 Other Events.**

***Investigation of Northern California Fires***

Since October 8, 2017, several catastrophic wildfires have started and remain active in Northern California. The causes of these fires are being investigated by the California Department of Forestry and Fire Protection (Cal Fire), including the possible role of power lines and other facilities of Pacific Gas and Electric Company's (the "Utility"), a subsidiary of PG&E Corporation.

It currently is unknown whether the Utility would have any liability associated with these fires. The Utility has approximately $800 million in liability insurance for potential losses that may result from these fires. If the amount of insurance is insufficient to cover the Utility's liability or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected.

**SIGNATURES**

**PG&E CORPORATION**

Dated: October 13, 2017

By: /s/ Jason P. Wells

JASON P. WELLS
Senior Vice President and Chief Financial Officer

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: October 13, 2017

By: /s/ David S. Thomason

DAVID S. THOMASON
Vice President, Chief Financial Officer and Controller

# Exhibit 13

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K

**CURRENT REPORT**
**Pursuant to Section 13 or 15(d)**
**of the Securities Exchange Act of 1934**

**Date of Report: November 2, 2017**
**(Date of earliest event reported)**

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

| PG&E Corporation | Pacific Gas and Electric Company |
|---|---|
| 77 Beale Street | 77 Beale Street |
| P.O. Box 770000 | P.O. Box 770000 |
| San Francisco, California 94177 | San Francisco, California 94177 |
| (Address of principal executive offices) (Zip Code) | (Address of principal executive offices) (Zip Code) |
| (415) 973-1000 | (415) 973-7000 |
| (Registrant's telephone number, including area code) | (Registrant's telephone number, including area code) |

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 2.02 Results of Operations and Financial Condition**

On November 2, 2017, PG&E Corporation will post on its website an earnings announcement disclosing its financial results and the financial results of its subsidiary, Pacific Gas and Electric Company ("Utility"), for the quarter ended September 30, 2017. The earnings announcement is attached as Exhibit 99.1 to this report. PG&E Corporation also will hold a webcast conference call to discuss financial results and management's business outlook. The earnings announcement contains information about how to access the webcast. The slide presentation, which includes supplemental information relating to PG&E Corporation and the Utility, will be used by management during the webcast and is attached as Exhibit 99.2 to this report. The Exhibits will be posted on PG&E Corporation's website at http://investor.pgecorp.com.

The information included in this Current Report on Form 8-K is being furnished, and shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that section, nor shall it be deemed to be incorporated by reference in any filing under the Securities Act of 1933, as amended (the "Securities Act").

**Item 7.01 Regulation FD Disclosure**

*Exhibits*

The information included in the Exhibits to this report is incorporated by reference in response to this Item 7.01, is being "furnished" and shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act or otherwise subject to the liabilities of that section, nor shall it be deemed to be incorporated by reference in any filing under the Securities Act.

*Public Dissemination of Certain Information*

PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings with the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC) at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "News & Events: Events & Presentations" tab, in order to publicly disseminate such information. The information contained on such websites is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the Securities and Exchange Commission.

**Item 9.01 Financial Statements and Exhibits**

Exhibits

The following Exhibits are being furnished, and are not deemed to be filed:

| | |
|---|---|
| Exhibit 99.1 | PG&E Corporation earnings announcement dated November 2, 2017 |
| Exhibit 99.2 | Slide presentation relating to webcast conference call |

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

**PG&E CORPORATION**

Dated: November 2, 2017

By: /s/ David S. Thomason
David S. Thomason
Vice President and Controller

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: November 2, 2017

By: /s/ David S. Thomason
David S. Thomason
Vice President, Chief Financial Officer and Controller

PG&E Corporation

Corporate Relations | 77 Beale Street | San Francisco, CA 94105 | 1 (415) 973-5930 | www.pgecorp.com

November 2, 2017

**PG&E Corporation Reports Third-Quarter 2017 Financial Results; Updates Investors on Response to the Northern California Wildfires and Support for Affected Communities**

- GAAP net income was $1.07 per share for the third quarter of 2017, compared with $0.77 per share for the same period in 2016.
- Non-GAAP earnings from operations were $1.12 per share for the third quarter of 2017, compared with $0.94 per share for the same period in 2016.
- PG&E Corporation is updating 2017 guidance for projected GAAP earnings to the range of $3.36 to $3.56 per share, and is reaffirming guidance for projected non-GAAP earnings in the range of $3.55 to $3.75 per share.

San Francisco, Calif. — PG&E Corporation's (NYSE: PCG) third-quarter 2017 net income after dividends on preferred stock (also called "income available for common shareholders") was $550 million or $1.07 per share, as reported in accordance with generally accepted accounting principles (GAAP). This compares with $388 million, or $0.77 per share, for the third quarter of 2016.

The quarter-over-quarter increase reflects lower expenses primarily due to the absence of disallowed charges related to the San Bruno Penalty Decision, which impacted the third quarter of 2016, and also due to insurance proceeds in the third quarter of 2017 related to the court-approved settlement of the shareholder derivative suit, with no similar amount in 2016.

GAAP results include items that management does not consider part of normal, ongoing operations (items impacting comparability), which totaled $39 million pre-tax, or $0.05 per share, for the quarter. For the third quarter of 2017, these included third-party claims and legal costs associated with the Butte fire, which were partially offset by accrued insurance recoveries. Other items included costs for work to clear pipeline rights-of-way, legal and regulatory costs related to regulatory communications, and the net benefit of proceeds from insurance related to the court-approved settlement of the shareholder derivative suit.

In addition to reviewing third-quarter financial results on today's earnings call, PG&E will also provide an update on the company's response to the recent Northern California wildfires.

PG&E Corporation CEO and President Geisha Williams said: "This is a very difficult time for our customers affected by the recent devastating wildfires, and they continue to be in our thoughts and prayers. We recognize that PG&E is going to play a vital part in helping these communities rebuild and recover. We are committed to working together and supporting them throughout that process. We also remain focused on continued investment in vital infrastructure and technology to increase the resilience and the sustainability of California's energy economy for the future."

**Northern California Wildfires Response**

PG&E worked with first responders and local communities to safely restore approximately 360,000 electric customers and 42,000 gas customers who lost service during the recent Northern California wildfires. Fueled by extraordinary winds and unusually dry conditions, the numerous fires resulted in the loss of 43 lives and burned thousands of homes and businesses in several counties. PG&E has committed more than $3 million to date in assistance to the local communities affected by the fires.

In those instances where Cal Fire investigators or PG&E identified a site potentially involving our facilities, PG&E submitted incident reports to the California Public Utilities Commission (CPUC). These reports are factual in nature and do not reflect a finding of cause. The company is fully cooperating with Cal Fire and the CPUC in their investigations of these fires.

PG&E maintains a robust vegetation management program to prevent trees and other vegetation from contacting the company's equipment. Beginning in 2016, the company approximately doubled its previous spending on line clearing and tree removal to respond to the tree mortality crisis in California. The company also enhanced its mitigation efforts with additional patrols of high-risk areas using a combination of aerial surveillance, foot patrols and LiDAR technology.

**Earnings from Operations**

On a non-GAAP basis, excluding items impacting comparability, PG&E Corporation's earnings from operations in the third quarter of 2017 were $578 million, or $1.12 per share, compared with $471 million, or $0.94 per share, in the third quarter of 2016. The increase reflected growth in rate base earnings, as well as positive impacts related to the timing of taxes, the timing of operational spending, and the timing of the phase-two decision in the 2015 GT&S rate case. These were partially offset by the loss of certain tax repair benefits in the 2017 GRC.

**Earnings Guidance**

PG&E Corporation is updating 2017 guidance for projected GAAP earnings in the range of $3.36 to $3.56 per share primarily due to the reinstatement of the company's liability insurance following the Northern California wildfires, as well as an increase in the expected third-party claims associated with the Butte fire, partially offset by accrued insurance recoveries. On a non-GAAP basis, the guidance range for projected 2017 earnings from operations remains unchanged at $3.55 to $3.75 per share, which assumes no material financial impact from the Northern California wildfires beyond the direct restoration and repair costs, the insurance reinstatement and some legal expenses.

Guidance is based on various assumptions and forecasts, including those relating to future authorized revenues, expenses, capital expenditures, rate base, equity issuances, and certain other factors. PG&E Corporation discloses historical financial results and provides guidance based on "earnings from operations" in order to provide a measure that allows investors to compare the underlying financial performance of the business from one period to another, exclusive of items impacting comparability. See the accompanying tables for a reconciliation of earnings from operations to consolidated income available for common shareholders.

**Supplemental Financial Information**

In addition to the financial information accompanying this release, presentation slides for today's conference call with the financial community have been furnished to the Securities and Exchange Commission (SEC) and are available on PG&E Corporation's website at: http://investor.pgecorp.com/financials/quarterly-earnings-reports/default.aspx.

**Public Dissemination of Certain Information**

PG&E Corporation and Pacific Gas and Electric Company routinely provide links to regulatory proceedings with the CPUC and the Federal Energy Regulatory Commission (FERC) at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "Events and Presentations" tab, in order to publicly disseminate such information.

**Conference Call with the Financial Community to Discuss Financial Results**

Today's call at 11:00 am, Eastern Time, is open to the public on a listen-only basis via webcast. Please visit http://investor.pgecorp.com/news-events/events-and-presentations/default.aspx for more information and instructions for accessing the webcast. The webcast call and the related materials will be available for replay through the website for at least one year. Alternatively, a toll-free replay of the conference call may be accessed shortly after the live call through November 16, 2017, by dialing (866) 415-9493. International callers may dial (205) 289-3247. For both domestic and international callers, the confirmation code 3278# will be required to access the replay.

**About PG&E Corporation**

PG&E Corporation (NYSE: PCG) is a Fortune 200 energy-based holding company, headquartered in San Francisco. It is the parent company of Pacific Gas and Electric Company, an energy company that serves 16 million Californians across a 70,000 square-mile service area in Northern and Central California. For more information, visit http://www.pgecorp.com. In this press release, they are together referred to as "PG&E."

**Forward-Looking Statements**

Management's statements providing guidance for PG&E Corporation's 2017 financial results and the assumptions and forecasts underlying such guidance, as well as statements regarding management's expectations and objectives for future periods, constitute forward-looking statements that reflect management's judgments and opinions. These statements, assumptions and forecasts are necessarily subject to various risks and uncertainties, the realization or resolution of which may be outside management's control. Actual results may differ materially. Factors that could cause actual results to differ materially include, but are not limited to:

- the impact of the Northern California wildfires, including the costs of restoration of service to customers and repairs to the Utility's facilities, and whether the Utility is able to recover such costs through CEMA; the timing and outcome of the investigations by Cal Fire and the CPUC, including as to the causes of the wildfires, and whether the Utility may have liability associated with these fires; and, if liable for one or more fires, whether the Utility would be able to recover all or part of such costs through insurance or through regulatory mechanisms, to the extent insurance is not available or exhausted; as well as potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;
- the Utility's ability to effectively manage capital expenditures and its operating and maintenance expenses within the authorized levels of spending and timely recover its costs through rates, and the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs;

- the timing and outcomes of the two TO rate cases pending before the FERC, and other ratemaking and regulatory proceedings;
- the timing and outcome of the Butte fire litigation; the timing and outcome of any proceeding to recover costs in excess of insurance from customers, if any; the effect, if any, of the SED's $8.3 million citations issued in connection with the Butte fire may have on the Butte fire litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Utility;
- the timing and outcomes of the ex parte OII and the safety culture OII;
- the outcome of the probation and the monitorship, the timing and outcomes of the debarment proceeding, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced, and the ultimate amount of fines, penalties, and remedial and other costs that the Utility may incur as a result;
- the outcomes of current and future self-reports, investigations or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations; and the timing and outcome of notices of violations in connection with the Yuba City incident;
- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms, and the amount and timing of additional common stock and debt issuances by PG&E Corporation;
- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity; whether the Utility is successful in addressing the changing industry landscape, including the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing for community choice aggregators;
- the impact of the increased cost of natural gas regulations;
- the timing and outcomes of the "Ghost Ship" and Valero refinery outage lawsuits;
- whether the Utility can continue to obtain insurance and whether insurance coverage is adequate for future losses or claims;
- changes in estimated environmental remediation costs, including costs associated with the Utility's natural gas compressor sites;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation, including as a result of the recent changes in the federal government;
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application; and
- the other factors disclosed in PG&E Corporation and the Utility's joint annual report on Form 10-K for the year ended December 31, 2016, their joint quarterly reports on Form 10-Q for the quarters ended March 31, June 30, and September 30, 2017, and other reports filed with the Securities and Exchange Commission (SEC), which are available on PG&E Corporation's website at www.pgecorp.com and on the SEC website at www.sec.gov.

**PG&E CORPORATION**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

| | (Unaudited) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (in millions, except per share amounts) | 2017 | 2016 | 2017 | 2016 |
| **Operating Revenues** | | | | |
| Electric | $ 3,648 | $ 3,994 | $10,036 | $10,590 |
| Natural gas | 869 | 816 | 2,999 | 2,363 |
| **Total operating revenues** | **4,517** | **4,810** | **13,035** | **12,953** |
| **Operating Expenses** | | | | |
| Cost of electricity | 1,466 | 1,613 | 3,436 | 3,719 |
| Cost of natural gas | 78 | 80 | 524 | 377 |
| Operating and maintenance | 1,364 | 1,783 | 4,414 | 5,631 |
| Depreciation, amortization, and decommissioning | 710 | 694 | 2,134 | 2,090 |
| **Total operating expenses** | **3,618** | **4,170** | **10,508** | **11,817** |
| **Operating Income** | **899** | **640** | **2,527** | **1,136** |
| Interest income | 9 | 8 | 22 | 17 |
| Interest expense | (220) | (211) | (663) | (621) |
| Other income, net | 25 | 24 | 59 | 74 |
| **Income Before Income Taxes** | **713** | **461** | **1,945** | **606** |
| Income tax provision (benefit) | 160 | 70 | 403 | (105) |
| **Net Income** | **553** | **391** | **1,542** | **711** |
| Preferred stock dividend requirement of subsidiary | 3 | 3 | 10 | 10 |
| **Income Available for Common Shareholders** | **$ 550** | **$ 388** | **$ 1,532** | **$ 701** |
| **Weighted Average Common Shares Outstanding, Basic** | **513** | **501** | **511** | **497** |
| **Weighted Average Common Shares Outstanding, Diluted** | **516** | **503** | **514** | **500** |
| **Net Earnings Per Common Share, Basic** | **$ 1.07** | **$ 0.77** | **$ 3.00** | **$ 1.41** |
| **Net Earnings Per Common Share, Diluted** | **$ 1.07** | **$ 0.77** | **$ 2.98** | **$ 1.40** |
| **Dividends Declared Per Common Share** | **$ 0.53** | **$ 0.49** | **$ 1.55** | **$ 1.44** |

See accompanying Notes to the Condensed Consolidated Financial Statements.

Reconciliation of PG&E Corporation's Consolidated Income Available for Common Shareholders in Accordance with Generally Accepted Accounting Principles ("GAAP") to Earnings from Operations
Third Quarter and Year to Date, 2017 vs. 2016
(in millions, except per share amounts)

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | Earnings | | Earnings per Common Share (Diluted) | | Earnings | | Earnings per Common Share (Diluted) | |
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| **PG&E Corporation's Earnings on a GAAP basis** | **$ 550** | **$ 388** | **$ 1.07** | **$ 0.77** | **$1,532** | **$ 701** | **$ 2.98** | **$1.40** |
| Items Impacting Comparability: (1) | | | | | | | | |
| Pipeline related expenses (2) | 12 | 18 | 0.02 | 0.04 | 45 | 47 | 0.09 | 0.10 |
| Legal and regulatory related expenses (3) | 1 | 14 | — | 0.03 | 5 | 32 | 0.01 | 0.06 |
| Fines and penalties (4) | 11 | 42 | 0.02 | 0.08 | 47 | 206 | 0.09 | 0.41 |
| Butte fire-related costs, net of insurance (5) | 42 | 9 | 0.08 | 0.02 | 27 | 110 | 0.05 | 0.22 |
| Net benefit from derivative litigation settlement (6) | (38) | — | (0.07) | — | (38) | — | (0.07) | — |
| GT&S revenue timing impact (7) | — | — | — | — | (88) | — | (0.17) | — |
| Diablo Canyon settlement-related disallowance (8) | — | — | — | — | 32 | — | 0.06 | — |
| GT&S capital disallowance | — | — | — | — | — | 113 | — | 0.23 |
| **PG&E Corporation's Earnings from Operations (9)** | **$ 578** | **$ 471** | **$ 1.12** | **$ 0.94** | **$1,562** | **$1,209** | **$ 3.04** | **$2.42** |

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except as indicated below.

(1) "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. See Exhibit titled Use of Non-GAAP Financial Measures.

(2) The Utility incurred costs of $20 million (before the tax impact of $8 million) and $76 million (before the tax impact of $31 million) during the three and nine months ended September 30, 2017, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

(3) The Utility incurred costs of $2 million (before the tax impact of $1 million) and $9 million (before the tax impact of $4 million) during the three and nine months ended September 30, 2017, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(4) The Utility incurred costs of $11 million (not tax deductible) and $71 million (before the tax impact of $24 million) during the three and nine months ended September 30, 2017, respectively, for fines and penalties. This includes disallowed expenses of $32 million (before the tax impact of $13 million) during the nine months ended September 30, 2017, associated with safety-related cost disallowances imposed by the California Public Utilities Commission ("CPUC") in its April 9, 2015 decision ("San Bruno Penalty Decision") in the gas transmission pipeline investigations. The Utility also recorded $15 million (before the tax impact of $6 million) during the nine months ended September 30, 2017, for disallowances imposed by the CPUC in its final phase two decision of the 2015 Gas Transmission and Storage ("GT&S") rate case for prohibited ex parte communications. In addition, the Utility recorded $11 million (not tax deductible) and $24 million (before the tax impact of $5 million) during the three and nine months ended September 30, 2017, respectively, in connection with the proposed decision and the settlement in the Order Instituting an Investigation into Compliance with Ex Parte Communication Rules ("ex parte OII").

| (in millions, pre-tax) | Three Months Ended September 30, 2017 | Nine Months Ended September 30, 2017 |
|---|---|---|
| Charge for disallowed expense | $ — | $ 32 |
| GT&S ex parte penalty | — | 15 |
| Ex parte OII settlement (tax deductible) | — | 12 |
| Ex parte OII settlement (not tax deductible) | 11 | 12 |
| **Fines and penalties** | $ 11 | $ 71 |

Future fines or penalties may be imposed in connection with other enforcement, regulatory, and litigation activities regarding regulatory communications.

(5) The Utility incurred costs of $71 million (before the tax impact of $29 million) and $46 million (before the tax impact of $19 million), during the three and nine months ended September 30, 2017, respectively, associated with the Butte fire, net of insurance. This includes accrued charges of $350 million (before the tax impact of $143 million), during the three and nine months ended September 30, 2017, related to estimated third-party claims. The Utility also incurred charges of $18 million (before the tax impact of $7 million) and $46 million (before the tax impact of $19 million), during the three and nine months ended September 30, 2017, respectively, for legal costs. These costs were partially offset by insurance recoveries of $297 million (before the tax impact of $121 million) and $350 million (before the tax impact of $143 million) recorded during the three and nine months ended September 30, 2017, respectively.

| (in millions, pre-tax) | Three Months Ended September 30, 2017 | Nine Months Ended September 30, 2017 |
|---|---|---|
| Third-party claims | $ 350 | $ 350 |
| Legal costs | 18 | 46 |
| Insurance | (297) | (350) |
| **Butte fire-related costs, net of insurance** | $ 71 | $ 46 |

(6) PG&E Corporation recorded proceeds from insurance, net of plaintiff payments, of $65 million (before the tax impact of $27 million) during the three and nine months ended September 30, 2017, associated with the settlement agreement in connection with the shareholder derivative litigation that was approved by the Superior Court of California, County of San Mateo, on July 18, 2017. This includes $90 million (before the tax impact of $37 million) during the three and nine months ended September 30, 2017, for proceeds from insurance, partially offset by $25 million (before the tax impact of $10 million) during the three and nine months ended September 30, 2017, for plaintiff legal fees paid in connection with the settlement.

(7) As a result of the CPUC's final phase two decision in the 2015 GT&S rate case, during the nine months ended September 30, 2017, the Utility recorded revenues of $150 million (before the tax impact of $62 million) in excess of the 2017 authorized revenue requirement, which includes the final component of under-collected revenues retroactive to January 1, 2015.

(8) As a result of the settlement agreement submitted to the CPUC in connection with the Utility's pending joint proposal to retire the Diablo Canyon Power Plant, the Utility recorded a total disallowance of $47 million (before the tax impact of $15 million) during the nine months ended September 30, 2017, comprised of cancelled projects of $24 million (before the tax impact of $6 million) and disallowed license renewal costs of $23 million (before the tax impact of $9 million), with no corresponding charges during the same periods in 2016. A portion of the cancelled projects and disallowed license renewal costs currently is not tax deductible.

(9) "Earnings from operations" is a non-GAAP financial measure. See Exhibit titled Use of Non-GAAP Financial Measures.

Key Drivers of PG&E Corporation's Earnings per Common Share ("EPS") from Operations
Third Quarter and YTD, 2017 vs. 2016
(in millions, except per share amounts)

| | Three Months Ended September 30, 2017 | | Nine Months Ended September 30, 2017 | |
|---|---|---|---|---|
| | Earnings | Earnings per Common Share (Diluted) | Earnings | Earnings per Common Share (Diluted) |
| 2016 Earnings from Operations (1) | $ 471 | $ 0.94 | $ 1,209 | $ 2.42 |
| Timing of taxes (2) | 42 | 0.08 | 90 | 0.18 |
| Timing of operational spend (3) | 31 | 0.06 | 31 | 0.06 |
| Growth in rate base earnings (4) | 27 | 0.05 | 78 | 0.15 |
| Timing of 2015 GT&S revenue impact (5) | 22 | 0.04 | 172 | 0.33 |
| Tax benefit on stock compensation (6) | — | — | 31 | 0.06 |
| Miscellaneous | 41 | 0.07 | 43 | 0.08 |
| Impact of 2017 GRC decision (7) | (56) | (0.10) | (92) | (0.18) |
| Increase in shares outstanding | — | (0.02) | — | (0.06) |
| **2017 Earnings from Operations (1)** | **$ 578** | **$ 1.12** | **$ 1,562** | **$ 3.04** |

(1) See Exhibit A for a reconciliation of EPS on a GAAP basis to EPS from Operations. All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except for tax benefits on stock compensation. See Footnote 6 below.

(2) Represents the timing of taxes reportable in quarterly statements in accordance with Accounting Standards Codification 740 and results from variance in percentage of quarterly earnings to annual earnings.

(3) Represents the timing of operational expense spending during the three months ended September 30, 2017 as compared to the same period in 2016.

(4) Represents the impact of the increase in rate base as authorized in various rate cases, including the 2017 General Rate Case ("GRC"), during the three and nine months ended September 30, 2017 as compared to the same periods in 2016.

(5) Represents the impact in 2016 of the delay in the Utility's 2015 GT&S rate case. The CPUC issued its final phase two decision on December 1, 2016, delaying recognition of the full 2016 revenue increase until the fourth quarter of 2016.

(6) Represents the incremental tax benefit related to share-based compensation awards that vested during the nine months ended September 30, 2017. Pursuant to ASU 2016-09, *Compensation – Stock Compensation (Topic 718)* , which PG&E Corporation and the Utility adopted in 2016, excess tax benefits associated with vested awards are reflected in net income.

(7) Represents the impact of lower tax repair benefits as a result of the CPUC's final decision in the 2017 GRC proceeding.

PG&E Corporation’s 2017 Earnings per Share (“EPS”) Guidance

| 2017 EPS Guidance | Low | High |
|---|---|---|
| **Estimated EPS on a GAAP Basis** | **$ 3.36** | **$ 3.56** |
| Estimated Items Impacting Comparability: (1) | | |
| Pipeline related expenses (2) | ~0.10 | ~0.10 |
| Legal and regulatory related expenses (3) | ~0.01 | ~0.01 |
| Fines and penalties (4) | ~0.09 | ~0.09 |
| Butte fire-related costs, net of insurance (5) | 0.05 | 0.05 |
| Net benefit from derivative litigation settlement (6) | (0.07) | (0.07) |
| GT&S revenue timing impact (7) | (0.17) | (0.17) |
| Diablo Canyon settlement-related disallowance (8) | ~0.06 | ~0.06 |
| Northern California wildfires (9) | ~0.12 | ~0.12 |
| **Estimated EPS on an Earnings from Operations Basis (10)** | **$ 3.55** | **$ 3.75** |

All amounts presented in the table above are tax adjusted at PG&E Corporation’s statutory tax rate of 40.75 percent, except as indicated below.

(1) “Items impacting comparability” represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. See Exhibit titled Use of Non-GAAP Financial Measures.

(2) “Pipeline related expenses” includes costs incurred to identify and remove encroachments from transmission pipeline rights-of-way. The pre-tax range of estimated costs is shown below. The offsetting tax impact for the low and high EPS guidance range is $37 million.

| | 2017 | |
|---|---|---|
| (in millions, pre-tax) | Low EPS guidance | High EPS guidance |
| Pipeline related expenses | ~$ 90 | ~$ 90 |

3) “Legal and regulatory related expenses” includes costs incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications. The pre-tax range of estimated costs is shown below. The offsetting tax impact for the low and high EPS guidance range is $4 million.

| | 2017 | |
|---|---|---|
| (in millions, pre-tax) | Low EPS guidance | High EPS guidance |
| Legal and regulatory related expenses | ~$ 10 | ~$ 10 |

(4) “Fines and penalties” includes fines and penalties resulting from various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications. Guidance is consistent with the disallowed expenses imposed by the CPUC in the San Bruno Penalty Decision in the gas transmission pipeline investigations, the disallowances imposed by the CPUC in its final phase two decision in the 2015 GT&S rate case for prohibited ex parte communications, and the CPUC’s proposed decision in connection with the ex parte OII. Guidance does not include amounts for other potential future fines and penalties. The pre-tax range of estimated costs is shown below. The offsetting tax impact for the low and high EPS guidance range is $24 million.

| | 2017 | |
|---|---|---|
| (in millions, pre-tax) | Low EPS guidance | High EPS guidance |
| Charge for disallowed expense | $ 32 | $ 32 |
| GT&S ex parte disallowance | 15 | 15 |
| Ex parte OII settlement | ~24 | ~24 |
| **Fines and penalties** | **~$ 71** | **~$ 71** |

(5) "Butte fire-related costs, net of insurance" refers to the costs associated with the Butte fire, net of insurance. The Utility currently is unable to estimate the low and high end of the guidance range of Butte fire-related third-party claims and legal costs for 2017. The offsetting tax impact is $19 million.

| | 2017 | |
|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | **High EPS guidance** |
| Butte fire-related costs, net of insurance | $ 46 | $ 46 |

(6) "Net benefit from derivative litigation settlement" refers to the settlement agreement in connection with the shareholder derivative litigation that was approved by the court on July 18, 2017. This amount includes proceeds from insurance net of plaintiff legal fees paid in connection with the settlement. The offsetting tax impact for the low and high EPS guidance range is $27 million.

| | 2017 | |
|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | **High EPS guidance** |
| Net benefit from derivative litigation settlement | $ (65) | $ (65) |

(7) "GT&S revenue timing impact" refers to the revenues recorded in excess of the 2017 authorized revenue requirements as a result of the CPUC's final phase two decision issued on December 1, 2016 in the 2015 GT&S rate case. Accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. Because the phase one decision issued by the CPUC directed the Utility to collect the difference between the adopted "interim" revenue requirements and the amounts previously collected in rates, retroactive to January 1, 2015, over a 36-month period, the Utility was not able to complete recording the full true-up of under-collected revenues until the first quarter of 2017. The pre-tax range of the recorded revenues is shown below. The offsetting tax impact for the low and high EPS guidance range is $62 million.

| | 2017 | |
|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | **High EPS guidance** |
| GT&S revenue timing impact | $ (150) | $ (150) |

(8) "Diablo Canyon settlement-related disallowance" refers to the settlement agreement submitted to the CPUC in connection with the Utility's pending joint proposal to retire the Diablo Canyon Power Plant, comprised of cancelled projects and disallowed license renewal costs. The offsetting tax impact for the low and high EPS guidance range is $15 million. A portion of the cancelled projects and disallowed license renewal costs currently is not tax deductible.

| | 2017 | |
|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | **High EPS guidance** |
| Diablo Canyon settlement-related disallowance | ~$ 47 | ~$ 47 |

(9) "Northern California wildfires" refers to costs associated with the Northern California wildfires including the reinstatement of liability insurance coverage, legal services and other expenses. The offsetting tax impact for the low and high EPS guidance range is $41 million.

| | 2017 | |
|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | **High EPS guidance** |
| Northern California wildfires | ~$ 100 | ~$ 100 |

(10) "Earnings from operations" is a non-GAAP financial measure. See Exhibit titled Use of Non-GAAP Financial Measures.

*Actual financial results for 2017 may differ materially from the guidance provided. For a discussion of the factors that may affect future results, see the Forward-Looking Statements.*

Use of Non-GAAP Financial Measures
PG&E Corporation and Pacific Gas and Electric Company

PG&E Corporation discloses historical financial results and provides guidance based on "earnings from operations" in order to provide a measure that allows investors to compare the underlying financial performance of the business from one period to another, exclusive of items impacting comparability.

"Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods, including certain pipeline related expenses, certain legal and regulatory related expenses, fines and penalties, Butte fire-related costs, net of insurance, net benefits from the derivative litigation settlement, GT&S revenue timing impact, the Diablo Canyon settlement-related disallowance, and the Northern California wildfires. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating planning, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance.

Earnings from operations are not a substitute or alternative for GAAP measures such as consolidated income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

Exhibit 99.2

PG&E Corporation

# THIRD QUARTER EARNINGS CALL

November 2, 2017

# Forward Looking Statements

This slide presentation contains statements regarding management's expectations and objectives for future periods as well as forecasts and estimates of PG&E Corporation's 2017 financial results, 2017 items impacting comparability, 2017 equity issuance, 2017-2019 capital expenditures and rate base growth, dividend policy, and general earnings sensitivities. These forecasts and estimates are based on 2017 assumptions, including but not limited to those relating to capital expenditures, authorized rate base and rate base growth assumptions, authorized cost of capital, and certain other factors. These statements, forecasts, estimates and assumptions constitute forward-looking statements that are necessarily subject to various risks and uncertainties and actual results may differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Factors that could cause actual results to differ materially include, but are not limited to:

- the impact of the Northern California wildfires, including the costs of restoration of service to customers and repairs to the Utility's facilities, and whether the Utility is able to recover such costs through CEMA; the timing and outcome of the investigations by Cal Fire and the CPUC, including as to the causes of the wildfires, and whether the Utility may have liability associated with these fires; and, if liable for one or more fires, whether the Utility would be able to recover all or part of such costs through insurance or through regulatory mechanisms, to the extent insurance is not available or exhausted; as well as potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;
- the Utility's ability to effectively manage capital expenditures and its operating and maintenance expenses within the authorized levels of spending and timely recover its costs through rates, and the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs;
- the timing and outcomes of the two TO rate cases pending before the FERC, and other ratemaking and regulatory proceedings;
- the timing and outcome of the Butte fire litigation; the timing and outcome of any proceeding to recover costs in excess of insurance from customers, if any; the effect, if any, of the SED's $8.3 million citations issued in connection with the Butte fire may have on the Butte fire litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Utility;
- the timing and outcomes of the ex parte OII and the safety culture OII;
- the outcome of the probation and the monitorship, the timing and outcomes of the debarment proceeding, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced, and the ultimate amount of fines, penalties, and remedial and other costs that the Utility may incur as a result;
- the outcomes of current and future self-reports, investigations or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations; and the timing and outcome of notices of violations in connection with the Yuba City incident;
- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms, and the amount and timing of additional common stock and debt issuances by PG&E Corporation;
- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity; whether the Utility is successful in addressing the changing industry landscape, including the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing for community choice aggregators;
- the impact of the increased cost of natural gas regulations;
- the timing and outcomes of the "Ghost Ship" and Valero refinery outage lawsuits;
- whether the Utility can continue to obtain insurance and whether insurance coverage is adequate for future losses or claims;
- changes in estimated environmental remediation costs, including costs associated with the Utility's natural gas compressor sites;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation, including as a result of the recent changes in the federal government;
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application; and
- the other factors disclosed in PG&E Corporation and the Utility's joint annual report on Form 10-K for the year ended December 31, 2016, their joint quarterly reports on Form 10-Q for the quarters ended March 31, June 30, and September 30, 2017, and other reports filed with the Securities and Exchange Commission (SEC), which are available on PG&E Corporation's website at www.pgecorp.com and on the SEC website at www.sec.gov.

*This presentation is not complete without the accompanying statements made by management during the webcast conference call held on November 2, 2017. The statements in this presentation are made as of November 2, 2017. PG&E Corporation undertakes no obligation to update information contained herein. This presentation, including Appendices, and the accompanying press release were attached to PG&E Corporation's Current Report on Form 8-K that was furnished to the SEC on November 2, 2017 and, along with the replay of the conference call, is also available on PG&E Corporation's website at www.pgecorp.com.*

# Northern California Wildfires

- Our thoughts and prayers are with the affected customers who experienced these extraordinary fires
- We conducted an unprecedented restoration effort and will continue helping our customers and communities as they rebuild
- We are committed to cooperating with Cal Fire and the CPUC as they conduct investigations

# Well-positioned to Deliver Strong Returns

### Building on Safety and Operational Performance

- Continuing focus on public, employee, and contractor safety
- Delivering reliable gas and electric service

### Delivering on Customer Expectations

- Improving customer service through continuous innovation
- Focusing on maintaining affordable service

### Positioning PG&E for Success

- Enabling California's clean energy economy
- Building coalitions

### Healthy 3-year growth profile

- ~6.5-7% ratebase growth
- Above average dividend growth

*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.*

# Q3 2017 Earnings Results

| | Q3 | | 2017 | |
|---|---|---|---|---|
| | Earnings (millions) | EPS | Earnings (millions) | EPS |
| **Earnings on a GAAP basis** | **$ 550** | **$ 1.07** | **$ 1,532** | **$ 2.98** |
| Items Impacting Comparability | | | | |
| Pipeline related expenses | 12 | 0.02 | 45 | 0.09 |
| Legal and regulatory related expenses | 1 | - | 5 | 0.01 |
| Fines and penalties | 11 | 0.02 | 47 | 0.09 |
| Butte fire-related costs, net of insurance | 42 | 0.08 | 27 | 0.05 |
| Net benefit from derivative litigation settlement | (38) | (0.07) | (38) | (0.07) |
| GT&S revenue timing impact | - | - | (88) | (0.17) |
| Diablo Canyon settlement-related disallowance | - | - | 32 | 0.06 |
| **Earnings from Operations** | **$ 578** | **$ 1.12** | **$ 1,562** | **$ 3.04** |

| **Items Impacting Comparability** (millions, pre-tax) | Q3 | 2017 |
|---|---|---|
| Pipeline related expenses | $ 20 | $ 76 |
| Legal and regulatory related expenses | 2 | 9 |
| Fines and penalties | 11 | 71 |
| Butte fire-related costs, net of insurance | 71 | 46 |
| Net benefit from derivative litigation settlement | (65) | (65) |
| GT&S revenue timing impact | - | (150) |
| Diablo Canyon settlement-related disallowance | - | 47 |
| **Total** | **$ 39** | **$ 34** |

*Earnings from Operations is not calculated in accordance with GAAP and excludes items impacting comparability. See Appendix, Exhibit A for a reconciliation of Earnings per Share ("EPS") on a GAAP basis to Earnings from Operations and Exhibit G for the use of non-GAAP financial measures.*

# Q3 2017: Quarter over Quarter Comparison


*Earnings from Operations is not calculated in accordance with GAAP and excludes items impacting comparability. See Appendix, Exhibit A for a reconciliation of Earnings per Share ("EPS") on a GAAP basis to Earnings from Operations and Exhibit G for the use of non-GAAP financial measures.*

# 2017 Earnings Per Share Guidance

| | Low | | High | |
|---|---|---|---|---|
| **Estimated EPS on a GAAP Basis** | **$** | **3.36** | **$** | **3.56** |
| Estimated Items Impacting Comparability | | | | |
| Pipeline related expenses | ~ | 0.10 | ~ | 0.10 |
| Legal and regulatory related expenses | ~ | 0.01 | ~ | 0.01 |
| Fines and penalties | ~ | 0.09 | ~ | 0.09 |
| Butte fire-related costs, net of insurance | | 0.05 | | 0.05 |
| Net benefit from derivative litigation settlement | | (0.07) | | (0.07) |
| GT&S revenue timing impact | | (0.17) | | (0.17) |
| Diablo Canyon settlement-related disallowance | ~ | 0.06 | ~ | 0.06 |
| Northern California wildfires | ~ | 0.12 | ~ | 0.12 |
| **Estimated EPS on an Earnings from Operations Basis** | **$** | **3.55** | **$** | **3.75** |

Changes from prior quarter noted in blue

*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.*
*See Appendix, Exhibit E for PG&E Corporation's 2017 Earnings per Share Guidance and Exhibit G for the Use of Non-GAAP Financial Measures.*

# 2017 Assumptions

PG&E

### Capital Expenditures
*($ millions)*

| | 2017 |
|---|---|
| General Rate Case | 3,700 |
| Gas Transmission and Storage | 900 |
| Transmission Owner 18 | 1,100 |
| **Total Cap Ex** | **~$5.7 billion** |

### Authorized Ratebase (weighted average)
*($ billions)*

| | 2017 |
|---|---|
| General Rate Case | 24.6 |
| Gas Transmission and Storage | 3.0 |
| Transmission Owner | 6.8 |
| **Total Ratebase** | **~$34.4 billion** |

### Authorized Cost of Capital*

**Return on Equity:** 10.4%

**Equity Ratio:** 52%

*CPUC authorized

### Other Factors Affecting Earnings from Operations

- GT&S amounts not requested
+ Incentive revenues and other benefits

CWIP earnings: offset by below-the-line costs

*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.*

# 2017 Items Impacting Comparability

| ($ millions, pre-tax) | | 2017 |
|---|---|---|
| Pipeline related expenses (1) | ~ | 90 |
| Legal and regulatory related expenses | ~ | 10 |
| Fines and penalties (2) | ~ | 71 |
| Butte fire-related costs, net of insurance | | 46 |
| Net benefit from derivative litigation settlement | | (65) |
| GT&S revenue timing impact | | (150) |
| Diablo Canyon settlement-related disallowance | ~ | 47 |
| Northern California wildfires | ~ | 100 |
| **2017 Items Impacting Comparability Total** | **~** | **$149** |

| Fines and Penalties ($ in millions, pre-tax) (2) | | |
|---|---|---|
| Charge for disallowed expense | | 32 |
| GT&S ex parte penalty | | 15 |
| Ex parte OII settlement | ~ | 24 |
| **Total** | **~** | **$71** |

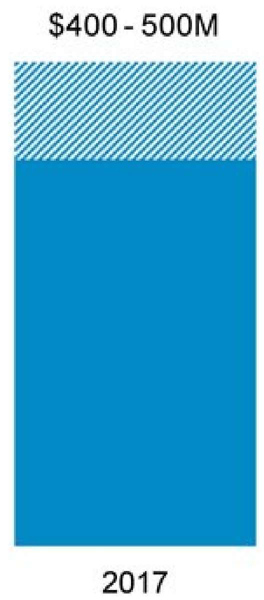
(1) Total cost of rights-of-way program expected to range from $450 million to $475 million

(2) Fines and penalties range excludes any additional potential future fines or penalties beyond those outlined above

Changes from prior quarter noted in blue

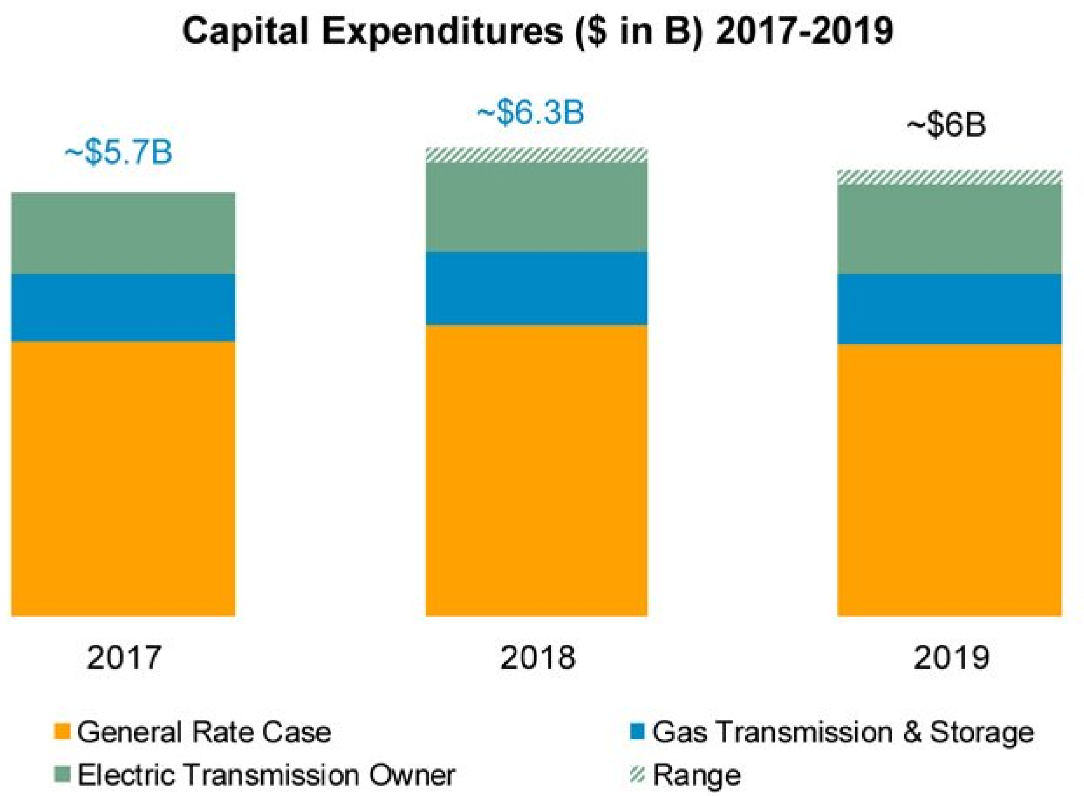
*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions. See Appendix, Exhibit E for PG&E Corporation's 2017 Earnings per Share Guidance and Exhibit G for Use of Non-GAAP Financial Measures.*

# 2017 Equity Issuance




*September 30, 2017 shares outstanding: ~514 million*

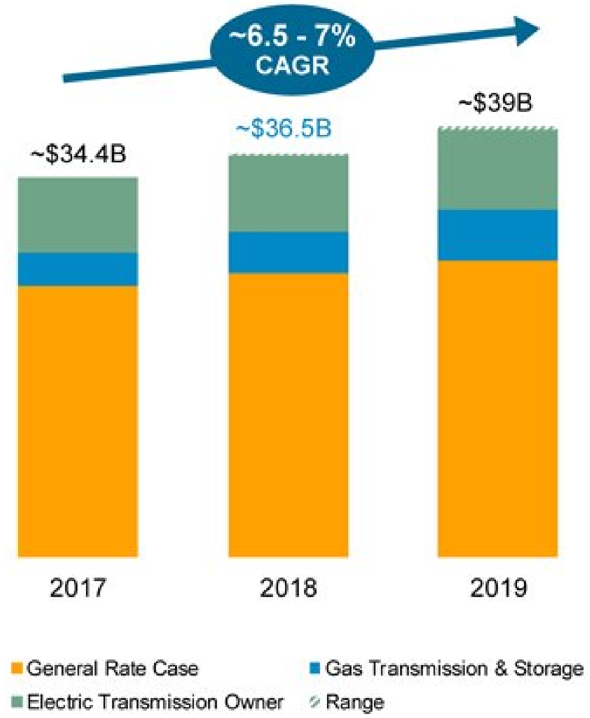
# Robust Cap Ex Supports Strong Returns




*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.*

# Ratebase Supports Strong Returns

**Weighted Average Ratebase ($ in B) 2017-2019**




**Base Case Assumptions:**

- 2017 General Rate Case through 2019
- 2015 Gas Transmission & Storage rate case
  - Phase 2 decision through 2018; flat in 2019
  - ~$400M for 2011-2014 spend subject to audit added in 2019
- Transmission Owner rate case:
  - High end: TO19 filing held flat through 2019
  - Low end: TO17 settlement held flat through 2019
- Electric Vehicle Infrastructure decision in December 2016

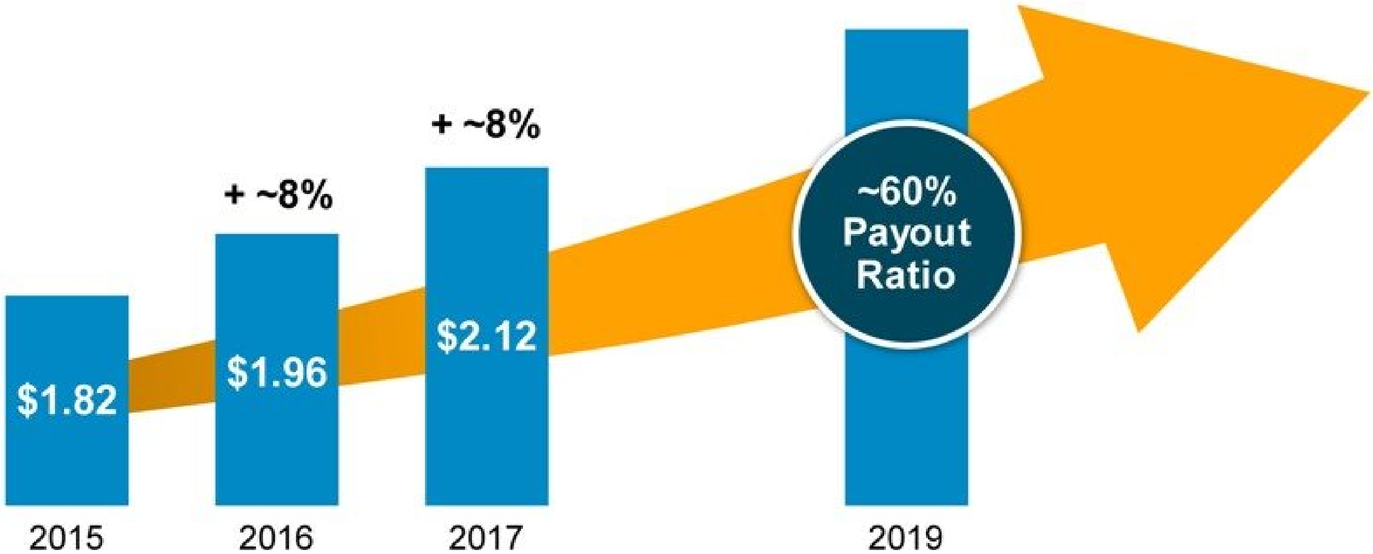
**Potential Future Updates:**

- 2019 Gas Transmission & Storage rate case
- 2018 and 2019 Transmission Owner rate cases
- State infrastructure modernization (e.g., rail and water projects)
- Future storage opportunities
- Future transportation electrification (e.g., January 2017 medium and heavy duty vehicle filing)
- New gas storage regulations

Changes from prior quarter noted in blue

*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.*

# Dividend Policy Supports Strong Total Shareholder Return




Targeting 55-65% payout ratio over time

*See the Forward Looking Statements for factors that could cause actual results to differ materially from the guidance presented and underlying assumptions.*

PG&E Corporation

# Appendix

# Appendix – Supplemental Earnings Materials


| | | |
|---|---|---|
| **Exhibit A:** | Reconciliation of PG&E Corporation's Consolidated Income Available for Common Shareholders in Accordance with Generally Accepted Accounting Principles to Earnings from Operations | Slides 16-17 |
| **Exhibit B:** | Key Drivers of PG&E Corporation's Earnings per Common Share from Operations | Slide 18 |
| **Exhibit C:** | Operational Performance Metrics | Slides 19-20 |
| **Exhibit D:** | Sales and Sources Summary | Slide 21 |
| **Exhibit E:** | PG&E Corporation's 2017 Earnings Per Share Guidance | Slides 22-23 |
| **Exhibit F:** | 2017 General Earnings Sensitivities | Slide 24 |
| **Exhibit G:** | Use of Non-GAAP Financial Measures | Slide 25 |
| **Exhibit H:** | Expected Timelines of Selected Regulatory Cases | Slides 26-30 |

# Exhibit A: Reconciliation of PG&E Corporation's Consolidated Income Available for Common Shareholders in Accordance with Generally Accepted Accounting Principles ("GAAP") to Earnings from Operations



| Third Quarter and Year to Date, 2017 vs. 2016 (in millions, except per share amounts) | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | Earnings | | Earnings per Common Share (Diluted) | | Earnings | | Earnings per Common Share (Diluted) | |
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| **PG&E Corporation's Earnings on a GAAP basis** | **$ 550** | **$ 388** | **$ 1.07** | **$ 0.77** | **$ 1,532** | **$ 701** | **$ 2.98** | **$ 1.40** |
| Items Impacting Comparability: (1) | | | | | | | | |
| Pipeline related expenses (2) | 12 | 18 | 0.02 | 0.04 | 45 | 47 | 0.09 | 0.10 |
| Legal and regulatory related expenses (3) | 1 | 14 | - | 0.03 | 5 | 32 | 0.01 | 0.06 |
| Fines and penalties (4) | 11 | 42 | 0.02 | 0.08 | 47 | 206 | 0.09 | 0.41 |
| Butte fire-related costs, net of insurance (5) | 42 | 9 | 0.08 | 0.02 | 27 | 110 | 0.05 | 0.22 |
| Net benefit from derivative litigation settlement (6) | (38) | - | (0.07) | - | (38) | - | (0.07) | - |
| GT&S revenue timing impact (7) | - | - | - | - | (88) | - | (0.17) | - |
| Diablo Canyon settlement-related disallowance (8) | - | - | - | - | 32 | - | 0.06 | - |
| GT&S capital disallowance | - | - | - | - | - | 113 | - | 0.23 |
| **PG&E Corporation's Earnings from Operations (9)** | **$ 578** | **$ 471** | **$ 1.12** | **$ 0.94** | **$ 1,562** | **$ 1,209** | **$ 3.04** | **$ 2.42** |

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except as indicated below.

(1) "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. See Exhibit G: Use of Non-GAAP Financial Measures.

(2) The Utility incurred costs of $20 million (before the tax impact of $8 million) and $76 million (before the tax impact of $31 million) during the three and nine months ended September 30, 2017, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

(3) The Utility incurred costs of $2 million (before the tax impact of $1 million) and $9 million (before the tax impact of $4 million) during the three and nine months ended September 30, 2017, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(4) The Utility incurred costs of $11 million (not tax deductible) and $71 million (before the tax impact of $24 million) during the three and nine months ended September 30, 2017, respectively, for fines and penalties. This includes disallowed expenses of $32 million (before the tax impact of $13 million) during the nine months ended September 30, 2017, associated with safety-related cost disallowances imposed by the California Public Utilities Commission ("CPUC") in its April 9, 2015 decision ("San Bruno Penalty Decision") in the gas transmission pipeline investigations. The Utility also recorded $15 million (before the tax impact of $6 million) during the nine months ended September 30, 2017, for disallowances imposed by the CPUC in its final phase two decision of the 2015 Gas Transmission and Storage ("GT&S") rate case for prohibited ex parte communications. In addition, the Utility recorded $11 million (not tax deductible) and $24 million (before the tax impact of $5 million) during the three and nine months ended September 30, 2017, respectively, in connection with the proposed decision and the settlement in the Order Instituting an Investigation into Compliance with Ex Parte Communication Rules ("ex parte OII").

| (in millions, pre-tax) | Three Months Ended September 30, 2017 | Nine Months Ended September 30, 2017 |
|---|---|---|
| Charge for disallowed expense | $ - | $ 32 |
| GT&S ex parte penalty | - | 15 |
| Ex parte OII settlement (tax deductible) | - | 12 |
| Ex parte OII settlement (not tax deductible) | 11 | 12 |
| **Fines and penalties** | $ 11 | $ 71 |

Future fines or penalties may be imposed in connection with other enforcement, regulatory, and litigation activities regarding regulatory communications.

(5) The Utility incurred costs of $71 million (before the tax impact of $29 million) and $46 million (before the tax impact of $19 million), during the three and nine months ended September 30, 2017, respectively, associated with the Butte fire, net of insurance. This includes accrued charges of $350 million (before the tax impact of $143 million), during the three and nine months ended September 30, 2017, related to estimated third-party claims. The Utility also incurred charges of $18 million (before the tax impact of $7 million) and $46 million (before the tax impact of $19 million), during the three and nine months ended September 30, 2017, respectively, for legal costs. These costs were partially offset by insurance recoveries of $297 million (before the tax impact of $121 million) and $350 million (before the tax impact of $143 million) recorded during the three and nine months ended September 30, 2017, respectively.

| (in millions, pre-tax) | Three Months Ended September 30, 2017 | Nine Months Ended September 30, 2017 |
|---|---|---|
| Third-party claims | $ 350 | $ 350 |
| Legal costs | 18 | 46 |
| **Insurnace** | (297) | (350) |
| **Butte fire-related costs, net of insurance** | $ 71 | $ 46 |

(6) PG&E Corporation recorded proceeds from insurance, net of plaintiff payments, of $65 million (before the tax impact of $27 million) during the three and nine months ended September 30, 2017, associated with the settlement agreement in connection with the shareholder derivative litigation that was approved by the Superior Court of California, County of San Mateo, on July 18, 2017. This includes $90 million (before the tax impact of $37 million) during the three and nine months ended September 30, 2017, for proceeds from insurance, partially offset by $25 million (before the tax impact of $10 million) during the three and nine months ended September 30, 2017, for plaintiff legal fees paid in connection with the settlement.

(7) As a result of the CPUC's final phase two decision in the 2015 GT&S rate case, during the nine months ended September 30, 2017, the Utility recorded revenues of $150 million (before the tax impact of $62 million) in excess of the 2017 authorized revenue requirement, which includes the final component of under-collected revenues retroactive to January 1, 2015.

(8) As a result of the settlement agreement submitted to the CPUC in connection with the Utility's pending joint proposal to retire the Diablo Canyon Power Plant, the Utility recorded a total disallowance of $47 million (before the tax impact of $15 million) during the nine months ended September 30, 2017, comprised of cancelled projects of $24 million (before the tax impact of $6 million) and disallowed license renewal costs of $23 million (before the tax impact of $9 million), with no corresponding charges during the same periods in 2016. A portion of the cancelled projects and disallowed license renewal costs currently is not tax deductible.

(9) "Earnings from operations" is a non-GAAP financial measure. See Exhibit G: Use of Non-GAAP Financial Measures.

# Exhibit B: Key Drivers of PG&E Corporation's Earnings per Common Share ("EPS") from Operations

Third Quarter and Year to Date, 2017 vs. 2016
(in millions, except per share amounts)

| | Three Months Ended September 30, 2017 | | Nine Months Ended September 30, 2017 | |
|---|---|---|---|---|
| | **Earnings** | **Earnings per Common Share (Diluted)** | **Earnings** | **Earnings per Common Share (Diluted)** |
| 2016 Earnings from Operations [(1)] | $ 471 | $ 0.94 | $ 1,209 | $ 2.42 |
| Timing of taxes [(2)] | 42 | 0.08 | 90 | 0.18 |
| Timing of operational spend [(3)] | 31 | 0.06 | 31 | 0.06 |
| Growth in rate base earnings [(4)] | 27 | 0.05 | 78 | 0.15 |
| Timing of 2015 GT&S revenue impact [(5)] | 22 | 0.04 | 172 | 0.33 |
| Tax benefit on stock compensation [(6)] | - | - | 31 | 0.06 |
| Miscellaneous | 41 | 0.07 | 43 | 0.08 |
| Impact of 2017 GRC decision [(7)] | (56) | (0.10) | (92) | (0.18) |
| Increase in shares outstanding | - | (0.02) | - | (0.06) |
| **2017 Earnings from Operations [(1)]** | **$ 578** | **$ 1.12** | **$ 1,562** | **$ 3.04** |

(1) See Exhibit A for a reconciliation of EPS on a GAAP basis to EPS from Operations. All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except for tax benefits on stock compensation. See Footnote 6 below.

(2) Represents the timing of taxes reportable in quarterly statements in accordance with Accounting Standards Codification 740 and results from variance in percentage of quarterly earnings to annual earnings.

(3) Represents the timing of operational expense spending during the three months ended September 30, 2017 as compared to the same period in 2016.

(4) Represents the impact of the increase in rate base as authorized in various rate cases, including the 2017 General Rate Case ("GRC"), during the three and nine months ended September 30, 2017 as compared to the same periods in 2016.

(5) Represents the impact in 2016 of the delay in the Utility's 2015 GT&S rate case. The CPUC issued its final phase two decision on December 1, 2016, delaying recognition of the full 2016 revenue increase until the fourth quarter of 2016.

(6) Represents the incremental tax benefit related to share-based compensation awards that vested during the nine months ended September 30, 2017. Pursuant to ASU 2016-09, *Compensation – Stock Compensation (Topic 718)*, which PG&E Corporation and the Utility adopted in 2016, excess tax benefits associated with vested awards are reflected in net income.

(7) Represents the impact of lower tax repair benefits as a result of the CPUC's final decision in the 2017 GRC proceeding.

## Exhibit C: Operational Performance Metrics

| 2017 Year to Date | Q3 Actual | EOY Target | Meets YTD Target [1] |
|---|---|---|---|
| **Safety (includes both public and employee safety metrics)** | | | |
| **Nuclear Operations Safety** | | | |
| Unit 1 Performance Indicator | 97.0 | 90.5 | ✓ |
| Unit 2 Performance Indicator | 90.0 | 87.6 | ✓ |
| **Electric Operations Safety** | | | |
| Electric Overhead Conductor Index | 1.467 | 1.000 | ✓ |
| 911 Emergency Response | 96.4% | 97.5% | - |
| **Gas Operations Safety** | | | |
| Gas In-Line Inspection and Upgrade Index | 1.4 | 1.0 | ✓ |
| Gas Dig-ins Reduction | 1.90 | 1.92 | ✓ |
| Gas Emergency Response | 20.3 | 21.0 | ✓ |
| **Employee Safety** | | | |
| SIF Corrective Action Index | 2.0 | 1.0 | ✓ |
| Serious Preventable Motor Vehicle Incident Rate | 0.262 | 0.239 | - |
| Timely Reporting of Injuries | 68.5% | 71.3% | - |
| **Customer** | | | |
| Customer Satisfaction Score | 75.3 | 76.4 | - |
| System Average Interruption Duration Index (SAIDI) | 86.8 | 107.0 | - |
| **Financial** | | | |
| Earnings from Operations | $1,562.0 | See note (1) | See note (1) |

*See following page for definitions of the operational performance metrics. The operational performance goals set under the PG&E Corporation 2017 Short Term Incentive Plan ("STIP") are based on the same operational metrics and targets.*

(1) The 2017 target for earnings from operations is not publicly reported but is consistent with the guidance range provided for 2017 EPS from operations of $3.55 to $3.75.

# Definitions of 2017 Operational Performance Metrics from Exhibit C

**Safety**

Public and employee safety are measured in four areas: (1) Nuclear Operations Safety, (2) Electric Operations Safety, (3) Gas Operations Safety, and (4) Employee Safety.

1. The safety of the Utility's nuclear power operations, Unit 1 and Unit 2, is an index comprised of 11 performance indicators for nuclear power generation that are regularly benchmarked against other nuclear power generators.
2. The safety of the Utility's electric operations is represented by (a) work that supports the safe reliable operations of the overhead electric system, and (b) the percentage of time that Utility personnel are on site within 60 minutes after receiving a 911 call of a potential Utility electric hazard.
3. The safety of the Utility's natural gas operations is represented by (a) the ability to complete planned in-line inspections and pipeline retrofit projects, measured by two equally weighted components of In-Line Inspections and In-Line Upgrades; (b) the number of third party "dig-ins" (i.e., damage resulting in repair or replacement of underground facility) to Utility gas assets per 1,000 Underground Service Alert tickets; and (c) the timeliness (measured in minutes) of on-site response to gas emergency service calls.
4. The safety of the Utility's employees is represented by (a) measuring the timely and quality completion of planned actions in response to Serious Injuries and Fatalities (SIF), (b) the number of serious preventable motor vehicle incidents that the driver could have reasonably avoided, per one million miles driven, and (c) the percentage of work-related injuries reported to the 24/7 Nurse Report Line within one day of the incident.

**Customer**

Customer satisfaction and service reliability are measured by:

1. The overall satisfaction (measured as a score of zero to 100) of customers with the products and services offered by the Utility, as measured through a quarterly survey performed by an independent third-party research firm.
2. The total time (measured in minutes) the average customer is without electric power during a given time period.

**Financial**

Earnings from Operations (shown in millions of dollars) measures PG&E Corporation's earnings from ongoing core operations. They allow investors to compare the underlying financial performance of the business from one period to another, exclusive of items that management believes do not reflect the normal course of operations (items impacting comparability). Earnings from Operations are not calculated in accordance with GAAP. For a reconciliation of Consolidated Income Available for Common Shareholders as reported in accordance with GAAP to Earnings from Operations, see Exhibit A.

# Exhibit D: Pacific Gas and Electric Company Sales and Sources Summary

Third Quarter and Year to Date, 2017 vs. 2016

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Sales from Energy Deliveries (in millions kWh) | 24,160 | 24,067 | 62,914 | 63,486 |
| Total Electric Customers at September 30 | | | 5,381,043 | 5,344,222 |
| | | | | |
| Total Gas Sales (in Bcf) | 183 | 200 | 560 | 593 |
| Total Gas Customers at September 30 | | | 4,465,259 | 4,438,565 |
| | | | | |
| Sources of Electric Energy (in millions kWh) | | | | |
| Total Utility Generation | 9,410 | 8,725 | 25,239 | 24,411 |
| Total Purchased Power | 9,189 | 12,560 | 25,905 | 32,327 |
| Total Electric Energy Delivered (1) | 24,160 | 24,067 | 62,914 | 63,486 |
| | | | | |
| Diablo Canyon Performance | | | | |
| Overall Capacity Factor (including refuelings) | 100% | 100% | 88% | 95% |
| Refueling Outage Period | None | None | 4/23-6/23 | 4/30-6/2 |
| Refueling Outage Duration during the Period | None | None | 61 | 33 |

(1) Includes other sources of electric energy totaling 5,561 million kWh and 2,782 million kWh for the three months ended September 30, 2017 and 2016, respectively, and 11,770 million kWh and 6,748 million kWh for the nine months ended September 30, 2017 and 2016, respectively.

*Please see the 2016 Annual Report on Form 10-K for additional information about operating statistics.*

| 2017 EPS Guidance | Low | | High | |
|---|---|---|---|---|
| **Estimated EPS on a GAAP Basis** | **$** | **3.36** | **$** | **3.56** |
| Estimated Items Impacting Comparability: [1] | | | | |
| Pipeline related expenses [2] | ~ | 0.10 | ~ | 0.10 |
| Legal and regulatory related expenses [3] | ~ | 0.01 | ~ | 0.01 |
| Fines and penalties [4] | ~ | 0.09 | ~ | 0.09 |
| Butte fire-related costs, net of insurance [5] | | 0.05 | | 0.05 |
| Net benefit from derivative litigation settlement [6] | | (0.07) | | (0.07) |
| GT&S revenue timing impact [7] | | (0.17) | | (0.17) |
| Diablo Canyon settlement-related disallowance [8] | ~ | 0.06 | ~ | 0.06 |
| Northern California wildfires [9] | ~ | 0.12 | ~ | 0.12 |
| **Estimated EPS on an Earnings from Operations Basis [10]** | **$** | **3.55** | **$** | **3.75** |

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 40.75 percent, except as indicated below.

(1) "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. See Exhibit G: Use of Non-GAAP Financial Measures.

(2) "Pipeline related expenses" includes costs incurred to identify and remove encroachments from transmission pipeline rights-of-way. The pre-tax range of estimated costs is shown below. The offsetting tax impact for the low and high EPS guidance range is $37 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Pipeline related expenses | ~ | 90 | ~ | 90 |

(3) "Legal and regulatory related expenses" includes costs incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications. The pre-tax range of estimated costs is shown below. The offsetting tax impact for the low and high EPS guidance range is $4 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Legal and regulatory related expenses | ~ | 10 | ~ | 10 |

(4) "Fines and penalties" includes fines and penalties resulting from various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications. Guidance is consistent with the disallowed expenses imposed by the CPUC in the San Bruno Penalty Decision in the gas transmission pipeline investigations, the disallowances imposed by the CPUC in its final phase two decision in the 2015 GT&S rate case for prohibited ex parte communications, and the CPUC's proposed decision in connection with the ex parte OII. Guidance does not include amounts for other potential future fines and penalties. The pre-tax range of estimated costs is shown below. The offsetting tax impact for the low and high EPS guidance range is $24 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Charge for disallowed expense | $ | 32 | $ | 32 |
| GT&S ex parte disallowance | | 15 | | 15 |
| Ex parte OII settlement | ~ | 24 | ~ | 24 |
| **Fines and penalties** | ~ | 71 | ~ | 71 |

(5) "Butte fire-related costs, net of insurance" refers to the costs associated with the Butte fire, net of insurance. The Utility currently is unable to estimate the low and high end of the guidance range of Butte fire-related third-party claims and legal costs for 2017. The offsetting tax impact is $19 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Butte fire-related costs, net of insurance | $ | 46 | $ | 46 |

(6) "Net benefit from derivative litigation settlement" refers to the settlement agreement in connection with the shareholder derivative litigation that was approved by the court on July 18, 2017. This amount includes proceeds from insurance net of plaintiff legal fees paid in connection with the settlement. The offsetting tax impact for the low and high EPS guidance range is $27 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Net benefit from derivative litigation settlement | $ | (65) | $ | (65) |

(7) "GT&S revenue timing impact" refers to the revenues recorded in excess of the 2017 authorized revenue requirements as a result of the CPUC's final phase two decision issued on December 1, 2016 in the 2015 GT&S rate case. Accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. Because the phase one decision issued by the CPUC directed the Utility to collect the difference between the adopted "interim" revenue requirements and the amounts previously collected in rates, retroactive to January 1, 2015, over a 36-month period, the Utility was not able to complete recording the full true-up of under-collected revenues until the first quarter of 2017. The pre-tax range of the recorded revenues is shown below. The offsetting tax impact for the low and high EPS guidance range is $62 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| GT&S revenue timing impact | $ | (150) | $ | (150) |

(8) "Diablo Canyon settlement-related disallowance" refers to the settlement agreement submitted to the CPUC in connection with the Utility's pending joint proposal to retire the Diablo Canyon Power Plant, comprised of cancelled projects and disallowed license renewal costs. The offsetting tax impact for the low and high EPS guidance range is $15 million. A portion of the cancelled projects and disallowed license renewal costs currently is not tax deductible.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Diablo Canyon settlement-related disallowance | ~ | 47 | ~ | 47 |

(9) "Northern California wildfires" refers to costs associated with the Northern California wildfires including the reinstatement of liability insurance coverage, legal services and other expenses. The offsetting tax impact for the low and high EPS guidance range is $41 million.

| | 2017 | | | |
|---|---|---|---|---|
| **(in millions, pre-tax)** | **Low EPS guidance** | | **High EPS guidance** | |
| Northern California wildfires | ~ | 100 | ~ | 100 |

(10) "Earnings from operations" is a non-GAAP financial measure. See Exhibit G: Use of Non-GAAP Financial Measures.

*Actual financial results for 2017 may differ materially from the guidance provided. For a discussion of the factors that may affect future results, see the Forward-Looking Statements.*

## Exhibit F: 2017 General Earnings Sensitivities
## PG&E Corporation and Pacific Gas and Electric Company

| Variable | Description of Change | Estimated 2017 Earnings Impact |
| --- | --- | --- |
| Rate base | +/- $100 million change in allowed rate base | +/- $5 million |
| Return on equity (ROE) | +/- 0.1% change in allowed ROE | +/- $18 million |
| Share count | +/- 1% change in average shares | +/- $0.04 per share |
| Revenues | +/- $9 million change in at-risk revenue (pre-tax), including Electric Transmission and Gas Transmission and Storage | +/- $0.01 per share |

*These general earnings sensitivities on factors that may affect 2017 earnings are forward-looking statements that are based on various assumptions. Actual results may differ materially. For a discussion of the factors that may affect future results, see the Forward-Looking Statements.*

**PG&E Corporation and Pacific Gas and Electric Company: Use of Non-GAAP Financial Measures**

PG&E Corporation discloses historical financial results and provides guidance based on "earnings from operations" in order to provide a measure that allows investors to compare the underlying financial performance of the business from one period to another, exclusive of items impacting comparability.

"Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods, including certain pipeline related expenses, certain legal and regulatory related expenses, fines and penalties, Butte fire-related costs, net of insurance, net benefits from the derivative litigation settlement, GT&S revenue timing impact, the Diablo Canyon settlement-related disallowance, and the Northern California wildfires. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating planning, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance.

Earnings from operations are not a substitute or alternative for GAAP measures such as consolidated income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

# Exhibit H: Pacific Gas and Electric Company
# Expected Timelines of Selected Regulatory Cases

| Regulatory Case | Docket # | Key Dates |
|---|---|---|
| 2017 General Rate Case (Phase I) | A. 15-09-001 | Sep 1, 2015 – Application Filed<br>Sep 29, 2015 – Application Workshop<br>Oct 29, 2015 – Prehearing conference<br>Jan 22, 2016 – PG&E Supplemental Testimony on gas distribution recordkeeping<br>Feb 22, 2016 – PG&E Supplemental Testimony on updated tax forecast, labor escalation<br>Apr 8, 2016 – ORA testimony<br>Apr 29, 2016 – Intervenor testimony<br>May-Jun, 2016 – Settlement discussions<br>May 2016 – Public participation hearings<br>May 27, 2016 – Rebuttal testimony<br>Aug 3, 2016 – Settlement with all parties that filed testimony submitted<br>Feb 27, 2017 – Proposed decision issued<br>May, 2017 – Final decision issued |
| Transmission Owner Rate Case (TO19) | ER17-2154 | Jul 26, 2017 – PG&E filed TO19 rate case seeking an annual revenue requirement for 2018<br>Sep 28, 2017 – FERC accepted TO19 making rates effective Mar 1, 2018 and establishing settlement process<br>Oct 23, 2017 – FERC settlement conference is scheduled<br>2018 – Add'l FERC settlement conference anticipated |
| Transmission Owner Rate Case (TO18) | ER16-2320 | Jul 29, 2016 – PG&E filed TO18 rate case seeking an annual revenue requirement for 2017<br>Sep 30, 2016 – FERC accepted TO18 making rates effective Mar 1, 2017 and establishing settlement process<br>Oct 19, 2016 – FERC settlement conference<br>Oct 30, 2016 – CPUC seeks rehearing of FERC's grant of 50 bp ROE adder for CAISO participation<br>Feb 7-8, 2017 – FERC settlement conference<br>Mar 16, 2017 – Parties reached impasse in settlement discussions<br>Jan 9, 2018 – Hearings scheduled to begin<br>Jun 1, 2018 – Initial decision expected |
| Safety Culture and Governance Order Instituting Investigation | I.15-08-019 | Sep 2, 2015 – OII issued<br>Oct 30, 2015 – PG&E submits discovery responses to SED<br>Dec 15, 2015 – PG&E submits discovery responses to SED<br>Jan 25, 2016 – PG&E submits discovery responses to SED<br>Apr 2016 – CPUC hires NorthStar as consultant for investigation<br>Apr 26-27, May 10-12, 2016 – Orientation presentations with SED and NorthStar staff<br>May 2016-Mar 2017 – Ongoing discovery (data requests, interviews, site visits, and demos) from NorthStar<br>May 8, 2017 – President Picker Phase II Scoping Memo and NorthStar Assessment Report Issued<br>Aug 1, 2017 – Prehearing Conference Scheduled<br>4Q 2017 – PG&E Testimony Due<br>1Q 2018 – Party Testimony Due<br>1Q 2018 – Evidentiary Hearings |

# Exhibit H: Pacific Gas and Electric Company
# Expected Timelines of Selected Regulatory Cases

| Regulatory Case | Docket # | Key Dates |
|---|---|---|
| 2015 Electric Distribution Resources Plan (DRP) | A.15-07-006, R.14-08-013 | Aug 13, 2014 – Commission issues OIR directing utilities to file Electric Distribution Resources Plans<br>Sep 5, 2014 – Comments on OIR<br>Sep 17, 2014 – Workshop I<br>Sep 22, 2014 – Reply Comments on OIR<br>Nov 17, 2014 – Draft Guidance Issued<br>Dec 12, 2014 – Comments on Draft Guidance<br>Jan 8, 2015 – Workshop II<br>Feb 6, 2015 – Final Guidance Ruling issued<br>Apr 13, 2015 – Workshop III<br>Jul 1, 2015 – PG&E files Electric Distribution Resources Plan<br>Aug 31, 2015 – Protests/comments due<br>Sep 15, 2015 – Replies to protests due<br>Sep 30, 2015 – Prehearing Conference<br>Nov 6, 2015 – Joint IOU/CAISO Workshop<br>Nov 9-10, 2015 – Integration Capacity Analysis (ICA) Workshop<br>Dec 3, 2015 – ICA Workshop Report filed<br>Jan 8, 2016 – ALJ Ruling inviting pre-workshop comments to Locational Net Benefits Analysis (LNBA) methodologies and Demonstration Project (Demo) B<br>Jan 26, 2016 – Pre-LNBA Workshop Comments Filed<br>Jan 27, 2016 – ACR/ALJ Ruling issuing Scope and Schedule<br>Feb 1, 2016 – LNBA, Alternate Proposal and Related Demo B Workshop<br>Feb 4, 2016 – Case reassigned to ALJ Kelly<br>Mar 2016 – Workshop on Field Demos C-F<br>Apr 2016 – DRP/IDER workshop to discuss sourcing mechanisms in Field Demos C-F<br>May 2016 – Comments on Field Demos C-F and alternatives<br>Jul 2016 – Proposed Decision on Field Demos C-F<br>Aug 2016 – Final Decision on Field Demos C-F<br>Sep 2016 – Begin Field Demos C-F<br>Jan 24, 2017 – Grid Modernization Workshop<br>Feb 9, 2017 – Decision on Field Demos C and D<br>Feb 27, 2017 – Decision on DER Growth Scenarion and Distribution Load Forecasting schedule<br>Mar 4, 2017 – PG&E filed updated Demo C project<br>Mar 8, 2017 – LNBA Working Group Final Report issued<br>Mar 15, 2017 – ICA Working Group Final Report issued<br>Apr 7, 2017 – PG&E filed DER forecasting methodology and assumptions<br>Apr 19, 2017 – Decision on scope of long–term refinements to ICA and LNBA<br>May 15, 2017 – Working group on ICA and LNBA long–term refinements<br>May 16, 2017 – CPUC Staff whitepaper on Grid Modernization<br>Jun 5, 2017 – Grid Modernization workshop |

# Exhibit H: Pacific Gas and Electric Company Expected Timelines of Selected Regulatory Cases

| Regulatory Case | Docket # | Key Dates |
|---|---|---|
| 2015 Electric Distribution Resources Plan (DRP) | A.15-07-006, R.14-08-013 | Jun 15, 2017 – Decision on PG&E's revised Field Demo D<br>Jun 19, 2017 – PG&E filed comments on CPUC Staff's Grid Modernization Whitepaper<br>Jun 22, 2017 – Decision requiring IOUs to file assumptions and framework details on DER growth forecasting and disaggregation<br>Jun 28, 2017 – PG&E filed assumptions and framework details on DER growth forecasting and disaggregation<br>Jun 30, 2017 – Decision requesting IOU comments on Energy Division staff proposal on the Distribution Investment Deferral Framework<br>Mid Jul, 2017 – Comments on CPUC Decision approving Field Demo C<br>Late Jul 2017 – Decision on IOU DER Growth Scenarios for distribution planning<br>Late Jul 2017 – Comments due on Energy Division's Distribution Investment Deferral Framework whitepaper<br>Aug 2017 – Reply Comments on Energy Division's Distribution Investment Deferral Framework whitepaper<br>Aug 2017 – Reply Comments on CPUC Decision approving Field Demo C<br>Oct 6, 2017 – Decision on ICA and LNBA use cases<br>Q3 2017 – Proposed Decision on DER Growth scenarios assumptions and framework<br>Q1 2018 – Proposed Decision on ICA and LNBA long-term refinements |
| Catastrophic Event Memorandum Account (CEMA) 2016 | A. 16-10-019 | Oct 31, 2016 – Application filed and testimony served<br>Dec 5, 2016 – Protests or responses<br>Dec 12, 2016 – Reply to protests or responses<br>Dec 19, 2016 – Prehearing conference<br>Oct 3, 2017 – Intervenor testimony<br>Oct 24, 2017 – Rebuttal testimony<br>Nov 6-9 , 2017 – Hearings<br>Dec 5, 2017 – Opening Briefs<br>Dec 22, 2017 – Reply Briefs<br>Q1, 2018 – Proposed Decision<br>Q2, 2018 – Final Decision |
| 2017 Integrated Resource Plan / Long Term Procurement Plan | R.16-02-007 | Feb 11, 2016 – CPUC opens Order Instituting Rulemaking<br>Mar 14, 2016 – Comments due on OIR<br>May 26, 2016 – Scoping Memo Issued<br>Jun 14, 2016 – Workshop on E3's Pathways Study hosted by State Agencies<br>Jun 23, 2016 – CPUC transfers significant modeling issues from legacy LTPP proceeding to R.16-02-007 proceeding (D.16-06-042)<br>Aug 11, 2016 – Staff Preliminary Proposal for an Integreated Resource Plan (IRP) Process Issued<br>Aug 23, 2016 – California Air Resources Board and CPUC Joint Workshop on ARB's 2030 Scoping Plan Update for the Energy Sector<br>Aug 31, 2016 – Parties submit comments on Staff's Preliminary Proposal for an IRP Process<br>Sep 26, 2016 – Workshop on Staff's Preliminary Proposal for an IRP Process<br>Oct 5, 2016 – Technical Advisory Group formed on modeling-related activities<br>Dec 2016 – Final Proposal for an IRP Process Issued by Staff<br>Sep 19, 2017 – Draft Reference System Plan issued<br>4Q 2017 – Decision adopting Reference System Plan<br>3Q 2018 – Load Serving Entities file individual Integrated Resource Plans |

# Exhibit H: Pacific Gas and Electric Company Expected Timelines of Selected Regulatory Cases

| Regulatory Case | Docket # | Key Dates |
|---|---|---|
| Integration of Distributed Energy Resources | R.14-10-003 | Sep 22, 2015 – Decision to expand scope to include distributed energy resources (DERs) on system side of customer's meter<br>Mar 24, 2016 – Working Group established to focus on contracting of DER products and services<br>Apr 4, 2016 – Assigned Commissioner Ruling (ACR) introducing a regulatory incentive proposal for DER deployment<br>Sep 1, 2016 – Amended Scoping Memo and Ruling re-categorizing all activities as rate-setting<br>Sep 22, 2016 – Workshop to begin considering societal cost test for DERs, including values of avoided societal costs<br>Dec, 2016 – Final Decision on competitive solicitation framework and regulatory incentives.<br>Mar 23, 2017 – PG&E and other IOUs filed opening comments on a ruling on Energy Division's Societal Cost Test (SCT) proposal.<br>Apr 6, 2017 – PG&E filed joint IOU reply comments on Energy Division's SCT proposal<br>Apr 17, 2017 – PG&E files comments on interim greenhouse gas adder for SCT<br>Apr 24, 2017 – PG&E filed joint IOU reply comments interim greenhouse gas adder for SCT<br>May 16, 2017 – Joint IOUs filed motion for hearing on the SCT proposals<br>Jun 16, 2017 – Ruling denying IOU's request for hearings on the SCT proposals and instead establishing a Workshop<br>Jun 22, 2017 – Proposed Decision to allow a 1–year waiver to updating the Avoided Cost Calculator<br>Jul 2017 – filed Advice Letter for DER Incentive Pilot<br>Aug 8, 2017 – Workshop on Energy Division's SCT proposal<br>Aug 10, 2017 – Expected decision allowing a 1–year waiver to updated the Avoided Cost Calculator |
| Diablo Canyon Retirement Joint Proposal Application | A.16-08-006 | Aug 11, 2016 – Application Filed<br>Sep 15, 2016 – Intervenor Protests<br>Oct 6, 2016 – Prehearing Conference<br>Oct 20, 2016 – Public Participation Hearings in San Luis Obispo<br>Dec 8, 2016 – Workshop at CPUC<br>Dec 28, 2016 – Community Impact Mitigation Settlement Filed with CPUC<br>Jan 27, 2017 – Intervenor Testimony & Comments On CIMP Settlement<br>Mar 17, 2017 – Rebuttal Testimony & PG&E's Response To Comments On CIMP Settlement<br>Apr 18-28, 2017 – Evidentiary Hearings<br>May 23, 2017 - License Renewal Project and Future Cancelled Project Settlement Agreement Filed<br>May 26, 2017 – Opening Briefs<br>Jun 16, 2017 – Reply Briefs<br>Jun 22, 2017 – Openning Comments on the License Renewal Project and Future Cancelled Project Settlement Agreement<br>Jul 7, 2017 – Reply Comments on the License Renewal Project and Future Cancelled Project Settlement Agreement<br>Sep 14, 2017 – Public Participation Hearings<br>Nov 28, 2017 – Final Oral Argument |
| Ex Parte Order Instituting Investigation and Order to Show Cause | I.15-11-015 | Nov 23, 2015 – OII issued<br>Dec 3, 2015 – City of San Bruno, City of San Carlos and TURN comments on need for evidentiary hearings, issues and schedule in the proceeding<br>Jan 8, 2016 – ALJ Bushey orders meet and confer among parties and sets prehearing conference date<br>Jan 27, 2016 – Parties meet to discuss issues for hearing and briefing<br>Jan 28, 2016 – PG&E (on behalf of parties) submits joint report on meet and confer to determine hearing issues<br>Feb 26, 2016 – Status report on resolving hearing issues due to Commission<br>Mar 1, 2016 – Prehearing conference |

# Exhibit H: Pacific Gas and Electric Company
# Expected Timelines of Selected Regulatory Cases

| Regulatory Case | Docket # | Key Dates |
|---|---|---|
| Ex Parte Order Instituting Investigation and Order to Show Cause | I.15-11-015 | Apr 18, 2016 – Joint meet and confer report filed by parties<br>Apr 20, 2016 – Prehearing conference<br>May 20, 2016 – Opening briefs on inclusion of additional emails ("Category 3")<br>Jun 10, 2016 – Reply briefs on inclusion of Category 3 emails<br>Jul 12, 2016 – Revised scoping memo<br>Sep 2016 – Status conference to set schedule for rest of proceeding<br>Jan 2017 – Commission grants two month extension to allow for additional settlement discussions<br>Mar 28, 2017 – PG&E, Cities of San Bruno and San Carlos, ORA, SED, and TURN submit joint settlement agreement<br>Jun 23, 2017 – Per an ALJ Ruling, PG&E submits supplemental briefing on joint settlement agreement |

*Most of these regulatory cases are discussed in PG&E Corporation and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2016.*

# Exhibit 14

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K

**CURRENT REPORT**
**Pursuant to Section 13 or 15(d)**
**of the Securities Exchange Act of 1934**

**Date of Report: November 27, 2017**
**(Date of earliest event reported)**

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.
**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
**(Address of principal executive offices) (Zip Code)**

**(415) 973-1000**
**(Registrant's telephone number, including area code)**

Pacific Gas and Electric Company
**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
**(Address of principal executive offices) (Zip Code)**

**(415) 973-7000**
**(Registrant's telephone number, including area code)**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 8.01 Other Events**

On November 27, 2017, Pacific Gas and Electric Company (the "Company"), a California corporation and subsidiary of PG&E Corporation ("Corp"), commenced a private offering pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"), of (i) floating rate senior notes due 2018 (the "2018 Floating Rate Senior Notes"), (ii) fixed rate senior notes due 2027 (the "2027 Senior Notes") and (iii) fixed rate senior notes due 2047 (the "2047 Senior Notes" and, together with the 2018 Floating Rate Senior Notes and the 2027 Senior Notes, the "Notes"), subject to market and other conditions. If the offering is consummated, the Company expects to use the net proceeds from the offering to repay all of the $700,000,000 outstanding principal amount of its 5.625% senior notes due November 30, 2017, all of the $250,000,000 outstanding principal amount of its floating rate senior notes due November 30, 2017 and the $250,000,000 floating rate unsecured term loan maturing February 22, 2018, and the balance, if any, for general corporate purposes, which may include capital expenditures, the repayment of outstanding commercial paper and the repayment of additional indebtedness.

The Notes have not been registered under the Securities Act or any state securities laws of any state of the United States, and may not be offered or sold within the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act.

In connection with the private offering of the Notes, Corp and the Company (together, the "Companies") are disclosing certain information to certain potential investors in a preliminary offering memorandum dated November 27, 2017 (the "Preliminary Offering Memorandum"). Pursuant to Regulation FD, the Companies are filing excerpts of the Preliminary Offering Memorandum hereto as Exhibit 99.1, which Exhibit is incorporated herein by reference.

This Current Report on Form 8-K does not constitute an offer to sell, or a solicitation of an offer to buy, any security. No offer, solicitation, or sale will be made in any jurisdiction in which such an offer, solicitation, or sale would be unlawful.

**Item 9.01 Financial Statements and Exhibits**

(d) Exhibits

| Exhibit No. | Description |
|---|---|
| 99.1 | Excerpts from the Preliminary Offering Memorandum |

**Cautionary Statement Concerning Forward-Looking Statements**

This communication and the documents incorporated by reference herein may contain "forward-looking" statements, as defined in federal securities laws including the Private Securities Litigation Reform Act of 1995, which are based on our current expectations, estimates, forecasts and projections. Statements that are not historical facts, including statements about the beliefs, expectations and future plans and strategies of the Companies, are forward-looking statements. Actual results may differ materially from those expressed in any forward-looking statements. These statements, assumptions and forecasts are necessarily subject to various risks and uncertainties, the realization or resolution of which may be outside management's control. Actual results may differ materially.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned hereunto duly authorized.

**PG&E CORPORATION**

By: /s/ David S. Thomason
David S. Thomason
Vice President and Controller

Dated: November 27, 2017

**PACIFIC GAS AND ELECTRIC COMPANY**

By: /s/ David S. Thomason
David S. Thomason
Vice President, Chief Financial Officer and Controller

Dated: November 27, 2017

**Excerpts from the Preliminary Offering Memorandum, dated November 27, 2017**

**Risks Related to Wildfires**

***Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected by potential losses resulting from the impact of the Northern California wildfires. The Company also expects to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions.***

Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected by potential losses resulting from the impact of the Northern California wildfires.

The Company currently estimates that it will incur costs in the range of $170 million to $200 million for service restoration and repairs to the Company's facilities (including an estimated $70 million to $80 million in capital expenditures) in connection with these fires. While the Company believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected if the Company were unable to recover such costs.

If the Company's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the theory of inverse condemnation applies, the Company could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on Corp and the Company. Courts have imposed liability under the theory of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the theory of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost recovery even if a court decision would have determined that the theory of inverse condemnation applies. In addition to such claims for property damage, interest and attorneys' fees, the Company could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Company were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on Corp and the Company. Further, the Company could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Company failed to comply with applicable laws and regulations.

Corp and the Company currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur given the preliminary stages of the investigations and the uncertainty as to the causes of the fires and the extent and magnitude of potential damages. On October 31, 2017, the California Department of Insurance issued a press release announcing an update on property losses stating that "[f]ifteen major insurers reported updated claims loss data to Insurance Commissioner Dave Jones revealing the new total of insured losses from the state's October wildfires now tops $3 billion—a three-fold increase in just two

weeks—and [is] expected to climb still higher according to department officials." (Previously, on October 19, 2017, the California Department of Insurance announced preliminary data provided by eight California insurers, reflecting $1.045 billion in property losses.) This estimate was based on a report of damage to 10,016 homes, destruction of 4,712 homes, damage or destruction to more than 728 businesses, and damage or destruction to 3,600 vehicles statewide. While the estimate of losses and supporting data relate to wildfires that occurred in October throughout California, Corp and the Company believe that most of this estimate of property losses relates to the Northern California wildfires. If the Company's facilities are determined to be the cause of one or more of the Northern California wildfires, Corp and the Company could be liable for the related property losses and other damages. The Insurance Commissioner's October 31, 2017 estimate reflects insured property losses only and is expected to increase. The estimate does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Company were to be found liable for certain or all of such other costs and expenses, the amount of Corp's and the Company's liability could be substantially higher than $3 billion, depending on the extent of the damage in connection with such fire or fires. As a result, Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected.

As of the date of this offering memorandum, the Company is aware of 32 lawsuits, one of which seeks to be designated as a class action, that have been filed against Corp and the Company in Sonoma, Napa and San Francisco Counties' Superior Courts. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that Corp's and the Company's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, two derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively. The first lawsuit is filed against the members of the Board of Directors and certain officers of Corp. Corp is identified as a nominal defendant in that action. The second lawsuit is filed against the members of the Board of Directors, certain former members of the Board of Directors, and certain officers of both Corp and the Company. Corp and the Company are identified as nominal defendants in that action. Corp and the Company expect to be the subject of additional lawsuits in connection with the Northern California wildfires.

The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Company has approximately $800 million in liability insurance for potential losses that may result from the Northern California wildfires. If the Company were to be found liable for one or more fires, the Company's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires. In addition, it could take a number of years before the Company's final liability is known and the Company could apply for cost recovery. The Company may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. Corp and the Company have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Company of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on Corp's and the Company's financial condition, results of operations, liquidity, and cash flows. Losses in connection with the wildfires would likely require Corp and the Company to seek financing, which may not be available when required. (See " *Risk Factors—Risks Related to Liquidity and Capital Requirements* " in this Offering Memorandum).

As of the date of this offering memorandum neither Corp nor the Company has accrued a liability in respect of the Northern California wildfires. If the Company were to determine that it is both probable that a loss has occurred and the amount of loss can be reasonably estimated, a liability would be recorded consistent with applicable accounting principles and as described in Note 13 to the consolidated financial statements in Corp and the Company's Annual Report on Form 10-K for the year ended December 31, 2016. To the extent not offset by

insurance recoveries determined to be similarly probable and estimable, the liability would reduce the balance sheet equity of Corp and the Company, which could adversely impact the Company's ability to maintain its CPUC-authorized capital structure of 52% equity and 48% debt and preferred stock, and which could also adversely impact Corp's and the Company's credit ratings and their ability to declare and pay dividends, efficiently raise capital, comply with financial covenants, and meet financial obligations. (See " *Risk Factors—Risks Related to Liquidity and Capital Requirements—PG&E Corporation 's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings* " in Corp and the Company's Annual Report on Form 10-K for the year ended December 31, 2016).

Uncertainties relating to and market perception of these matters and the disclosure of findings regarding these matters over time, also could lead to volatility in the market for Corp's common stock and other securities, and for the securities of the Company, and materially affect the price of such securities.

For additional information about risks that Corp and the Company face with respect to wildfires, see " *Risk Factors—Risks Related to Operations and Information Technology— The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial results. The Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event, or may not become available at a reasonable cost, or available at all* " in Corp and the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

***Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability that the Company incurs in connection with the Butte fire.***

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. Cal Fire's report concluded that the wildfire was caused when a gray pine tree contacted the Company's electric line which ignited portions of the tree, and determined that the failure by the Company and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

As of the date of this offering memorandum, 77 known complaints have been filed against the Company and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,772 individual plaintiffs representing approximately 2,045 households and their insurance companies. These complaints are part of or are in the process of being added to two master complaints. Plaintiffs seek to recover damages and other costs, principally based on inverse condemnation and negligence theories of liability. Plaintiffs also seek punitive damages. The number of individual complaints and plaintiffs may increase in the future. The Company continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint with the Superior Court of the State of California, County of Calaveras, seeking to recover $87 million for its costs incurred in connection with the Butte fire on the theory that the Company and its vegetation management contractors were negligent, among other claims. Also, in May 2017, the OES indicated that it intends to bring a claim against the Company that it estimates in the approximate amount of $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Company that it estimates in the approximate amount of $85 million. This claim would include costs that the County of Calaveras incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire.

As disclosed in Corp and the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, the Company determined as of September 30, 2017 that it is probable that it will incur a loss of at least

$1.1 billion, increased from the $750 million previously estimated as of December 31, 2016, in connection with the Butte fire. In addition, while this amount includes the Company's early assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Company still does not have sufficient information to reasonably estimate any liability it may have for these additional claims.

The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs and results from the ongoing mediation and settlement process, management's estimates and assumptions regarding the financial impact of the Butte fire may change. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on Corp's and the Company's financial condition, results of operations, liquidity, and cash flows.

Through September 30, 2017, the amounts accrued in connection with claims relating to the Butte fire have exceeded the Company's liability insurance coverage. While the Company filed an application with the CPUC requesting approval to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Company to request recovery of wildfire costs that have not otherwise been recovered through insurance or other mechanisms, the Company cannot predict the outcome of this proceeding. If the Company is unable to recover all or a significant portion of such excess costs, Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially affected.

**Risks Related to Liquidity and Capital Requirements**

***The outcome or market perception of the investigations and litigation in connection with the Northern California wildfires, and the outcome or market perception of other litigation and enforcement matters, could reduce or eliminate Corp's and the Company's access to the capital markets and other sources of financing, which could have a material adverse effect on Corp and the Company.***

Corp's and the Company's liquidity is dependent on many factors, including access to the capital markets and access to availability under their revolving credit facilities and commercial paper program. Corp's and the Company's ability to access the capital markets, to borrow under their loan financing arrangements, including their revolving credit facilities, and the terms and rates of future financings, as well as the credit ratings of Corp and the Company and their respective debt facilities, could be materially adversely affected by the outcome or market perception of the matters discussed in this offering memorandum under "The Northern California Wildfires" and in Note 9 and Note 10 to the condensed consolidated financial statements in the Company's

Quarterly Report on Form 10-Q for the period ended September 30, 2017. Liabilities that could be incurred as a result of the recent Northern California wildfires could adversely affect their ability to comply with the covenants in their financing arrangements, which could adversely affect the ability to borrow under the applicable facility or program.

Access by Corp to the equity capital markets is also critical to maintaining the Company's CPUC-authorized capital structure. Corp contributes equity to the Company as needed to maintain the Company's CPUC-authorized capital structure. For the nine months ended September 30, 2017, Corp issued $361 million of common stock and made equity contributions of $405 million to the Company. Corp forecasts that it will need to continue to issue a material amount of equity in future years, including to support the Company's capital expenditures. Corp may also seek to issue additional equity to fund unrecoverable operating expenses and to pay claims, losses, fines and penalties that may be required by the outcome of enforcement matters and litigation, including in connection with the Northern California wildfires, and the outcome of the related CPUC and Cal Fire investigations.

If Corp or the Company is unable to access the capital markets or to borrow under their respective loan financing arrangements or commercial paper program, Corp and the Company's financial condition, results of operations, liquidity, and cash flows, could be materially adversely affected.

***Corp's and the Company's ability to meet their debt service and other financial obligations and their ability to pay dividends depend on the Company's earnings and cash flows. In addition, if either of the Boards of Directors were to choose to not declare dividends in the future, the ability of Corp and the Company to raise equity capital could be adversely affected.***

Corp is a holding company with no revenue generating operations of its own. The Company must use its resources to satisfy its own obligations, including the Company's obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends and meet its obligations to employees and creditors, before it can distribute cash to Corp. Under the CPUC's rules applicable to utility holding companies, the Company's dividend policy must be established by the Company's Board of Directors as though the Company were a stand-alone utility company and Corp's Board of Directors give "first priority" to the Company's capital requirements, as determined to be necessary and prudent to meet the Company's obligation to serve or to operate the Company in a prudent and efficient manner. The CPUC has interpreted this "first priority" obligation to include the requirement that Corp "infuse the Company with all types of capital necessary for the Company to fulfill its obligation to serve". In addition, before the Company can pay common stock dividends to Corp, the Company must maintain its authorized capital structure with an average 52% equity component.

If the Company were required to pay a material amount of fines or incur material unrecoverable costs in connection with the terms of the probation or monitorship, the pending CPUC investigations, the Butte fire, the Northern California wildfires, or other liabilities or enforcement matters, it would require incremental equity contributions from Corp to restore its capital structure. Corp common stock issuances used to fund such equity contributions could materially dilute earnings per share. (See "Liquidity and Financial Resources" in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2016). Further, if Corp were required to infuse the Company with significant capital or if the Company was unable to distribute cash to Corp, or both, Corp may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend or meet other obligations.

In May 2017, the Board of Directors of Corp approved a new annual common stock cash dividend of $2.12 per share ($0.53 per share quarterly), which is equal to an estimated annual cash dividend of $1.08 billion in the aggregate, based on approximately 510.6 million shares outstanding on the record date for the 2017 annual meeting, and the Board of Directors of the Company approved a new annual common stock cash dividend of $1.08 billion ($270 million quarterly). Each of the Boards of Directors of Corp and the Company retains authority to change its annual dividend at any time, especially if unexpected events occur that would change such

Board's views as to the prudent level of cash conservation. No dividends are payable until after the respective Board of Directors declares a dividend. If the Board of Directors of Corp were to reduce, suspend or eliminate dividends, such reduction, suspension or elimination of dividend could lead to volatility in the market for Corp's common stock and other securities, and for the securities of the Company, materially affect the price of such securities, and could adversely affect the ability of Corp to raise additional equity capital.

### Risks Related to an Investment in the Senior Notes and this Offering

***If the Company were to be found liable for one of more of the Northern California wildfires, Corp and the Company would likely require additional financing, which may include secured indebtedness to which the senior notes offered hereby would be effectively subordinated.***

If the Company were to be found liable for one or more of the Northern California wildfires, Corp and the Company would likely require additional financing, which may be substantial, to satisfy obligations as they become due, including claims for property damages, interest and attorneys' fees, fire suppression costs, personal injury damages, and other damages. Any such financing could take a number of forms, including indebtedness incurred by the Company secured by liens on the Company's assets, in which case the senior notes offered hereby would be effectively subordinated to such indebtedness to the extent of the value of such collateral. Such new financing could also require amortization, mandatory redemption or have near-term maturities, such that substantial cash outflows could occur prior to the maturity of the senior notes offered hereby. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy existing financial obligations, including those relating to the senior notes offered hereby.

## THE NORTHERN CALIFORNIA WILDFIRES

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City. According to the California Department of Forestry and Fire Protection ("Cal Fire") California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures.

The causes of these fires are being investigated by Cal Fire and the CPUC, including the possible role of the Company's power lines and other facilities. The Company expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. The CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

As of the date of this offering memorandum, the Company had submitted 21 electric incident reports to the CPUC involving the Company's facilities in and around the areas impacted by the Northern California wildfires. Electric utilities must report to the CPUC incidents that are attributable or allegedly attributable to utility-owned facilities and (1) result in fatality or personal injury rising to the level of in-patient hospitalization; (2) are the subject of significant public attention or media coverage; or (3) involve damage to property of the Company or others estimated to exceed $50,000. The information contained in these reports is factual and does not include a determination of the causes of the fires. The investigations into the causes of the fires are ongoing.

The Company currently estimates that it will incur costs in the range of $170 million to $200 million for service restoration and repairs to the Company's facilities (including an estimated $70 million to $80 million in capital expenditures) in connection with these fires. While the Company believes that such costs are recoverable through Catastrophic Event Memorandum Account ("CEMA"), its CEMA requests are subject to CPUC approval. The Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected if the Company were unable to recover such costs.

If the Company's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the theory of inverse condemnation applies, the Company could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on Corp and the Company. Courts have imposed liability under the theory of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the theory of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost recovery even if a court decision would have determined that the theory of inverse condemnation applies. In addition to such claims for property damage, interest and attorneys' fees, the Company could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Company were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on Corp and the Company. Further, the Company could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Company failed to comply with applicable laws and regulations.

Corp and the Company currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur given the preliminary stages of the investigations and the uncertainty as to the

causes of the fires and the extent and magnitude of potential damages. On October 31, 2017, the California Department of Insurance issued a press release announcing an update on property losses stating that "[f]ifteen major insurers reported updated claims loss data to Insurance Commissioner Dave Jones revealing the new total of insured losses from the state's October wildfires now tops $3 billion—a three-fold increase in just two weeks—and [is] expected to climb still higher according to department officials." (Previously, on October 19, 2017, the California Department of Insurance announced preliminary data provided by eight California insurers, reflecting $1.045 billion in property losses.) This estimate was based on a report of damage to 10,016 homes, destruction of 4,712 homes, damage or destruction to more than 728 businesses, and damage or destruction to 3,600 vehicles statewide. While the estimate of losses and supporting data relate to wildfires that occurred in October throughout California, Corp and the Company believe that most of this estimate of property losses relates to the Northern California wildfires. If the Company's facilities are determined to be the cause of one or more of the Northern California wildfires, Corp and the Company could be liable for the related property losses and other damages. The Insurance Commissioner's October 31, 2017 estimate reflects insured property losses only and is expected to increase. The estimate does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Company were to be found liable for certain or all of such other costs and expenses, the amount of Corp's and the Company's liability could be substantially higher than $3 billion, depending on the extent of the damage in connection with such fire or fires. As a result, Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected.

As of the date of this offering memorandum, the Company is aware of 32 lawsuits, one of which seeks to be designated as a class action, that have been filed against Corp and the Company in Sonoma, Napa and San Francisco Counties' Superior Courts. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that Corp's and the Company's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, two derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively. The first lawsuit is filed against the members of the Board of Directors and certain officers of Corp. Corp is identified as a nominal defendant in that action. The second lawsuit is filed against the members of the Board of Directors, certain former members of the Board of Directors, and certain officers of both Corp and the Company. Corp and the Company are identified as nominal defendants in that action. Corp and the Company expect to be the subject of additional lawsuits in connection with the Northern California wildfires.

The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Company has approximately $800 million in liability insurance for potential losses that may result from the Northern California wildfires. If the Company were to be found liable for one or more fires, the Company's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires. In addition, it could take a number of years before the Company's final liability is known and the Company could apply for cost recovery. The Company may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. Corp and the Company have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Company of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on Corp's and the Company's financial condition, results of operations, liquidity, and cash flows.

Following the Northern California wildfires, Corp reinstated its liability insurance in the amount of approximately $630 million for any potential future event.

For additional information about risks that Corp and the Company face with respect to the Northern California wildfires, see *"Risk Factors—Risks Related to the Wildfires—Corp's and the Company's financial condition, results of operations, liquidity, and cash flows could be materially adversely affected by potential losses resulting from the impact of the Northern California wildfires. The Company also expects to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions"* and other related risks in the Risk Factors section of this Offering Memorandum.

# Exhibit 15

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# FORM 8-K

**CURRENT REPORT**

**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**Date of Report: December 20, 2017**
(Date of earliest event reported)

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

| PG&E Corporation | Pacific Gas and Electric Company |
|---|---|
| **77 Beale Street** | **77 Beale Street** |
| **P.O. Box 770000** | **P.O. Box 770000** |
| **San Francisco, California 94177** | **San Francisco, California 94177** |
| (Address of principal executive offices) (Zip Code) | (Address of principal executive offices) (Zip Code) |
| **(415) 973-1000** | **(415) 973-7000** |
| (Registrant's telephone number, including area code) | (Registrant's telephone number, including area code) |

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 8.01 Other Events.**

On December 20, 2017, the Boards of Directors of PG&E Corporation (the "Corporation") and its subsidiary, Pacific Gas and Electric Company (the "Utility"), determined to suspend quarterly cash dividends on both the Corporation's common stock, beginning with the fourth quarter of 2017, and the Utility's preferred stock, beginning with the three-month period ending January 31, 2018, due to uncertainty related to causes and potential liabilities associated with the extraordinary October 2017 Northern California wildfires.

A copy of the related press release is attached as Exhibit 99.1 to this Current Report on Form 8-K.

For information regarding the Northern California wildfires and risks that PG&E Corporation and the Utility face in connection with such wildfires, see PG&E Corporation and the Utility's Quarterly Report on Form 10-Q for the period ended September 30, 2017, and their Current Report on Form 8-K dated November 27, 2017.

**Item 9.01 Financial Statements and Exhibits**

Exhibit 99.1 Press Release dated December 20, 2017

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

**PG&E CORPORATION**

Dated: December 20, 2017

By: /s/ LINDA Y.H. CHENG
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: December 20, 2017

By: /s/ LINDA Y.H. CHENG
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

PG&E Corporation

Marketing & Communications | 77 Beale Street | San Francisco, CA 94105 | 415.973.5930 | www.pgecorp.com

**December 20, 2017**

# PG&E Announces Suspension of Dividend, Citing Uncertainty Related to Causes and Potential Liabilities Associated with Northern California Wildfires

**SAN FRANCISCO, Calif.** —PG&E Corporation (NYSE: PCG) today announced that its Board of Directors has determined to suspend the quarterly cash dividend on the Corporation's common stock, beginning with the fourth quarter of 2017, citing uncertainty related to causes and potential liabilities associated with the extraordinary October 2017 Northern California wildfires.

In addition, the Board of Directors of the Corporation's utility subsidiary, Pacific Gas and Electric Company, determined to suspend the dividend on the utility's preferred stock, beginning with the three-month period ending Jan. 31, 2018, citing the same uncertainty.

No causes have yet been identified for any of the unprecedented wildfires, which continue to be the subject of ongoing investigations.

However, California is one of the only states in the country in which courts have applied inverse condemnation to events caused by utility equipment. This means that if a utility's equipment is found to have been a substantial cause of the damage in an event such as a wildfire – even if the utility has followed established inspection and safety rules – the utility may still be liable for property damages and attorneys' fees associated with that event.

"After extensive consideration and in light of the uncertainty associated with the causes and potential liabilities associated with these wildfires as well as state policy uncertainties, the PG&E boards determined that suspending the common and preferred stock dividends is prudent with respect to cash conservation and is in the best long-term interests of the companies, our customers and our shareholders," said PG&E Corporation Chair of the Board Richard C. Kelly.

"We fully recognize the importance of dividends and intend to revisit the issue as we get more clarity. In the meantime, PG&E is committed to working with state policymakers to address the negative investment environment that strict liability under inverse condemnation is creating for California's utilities. This ultimately hurts our customers and the state. The company also remains committed to supporting recovery and rebuilding efforts by those communities that were impacted by these devastating fires," he said.

## About PG&E Corporation

PG&E Corporation (NYSE: PCG) is a Fortune 200 energy-based holding company, headquartered in San Francisco. It is the parent company of Pacific Gas and Electric Company, California's largest investor-owned utility. PG&E serves nearly 16 million Californians across a 70,000 square-mile service area in Northern and Central California. For more information, visit www.pgecorp.com and www.pge.com.

# Exhibit 16

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K

**CURRENT REPORT**
**Pursuant to Section 13 or 15(d)**
**of the Securities Exchange Act of 1934**

**Date of Report: June 8, 2018**
**(Date of earliest event reported)**

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

| PG&E Corporation | Pacific Gas and Electric Company |
|---|---|
| 77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177<br>(Address of principal executive offices) (Zip Code) | 77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177<br>(Address of principal executive offices) (Zip Code) |
| (415) 973-1000<br>(Registrant's telephone number, including area code) | (415) 973-7000<br>(Registrant's telephone number, including area code) |

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 7.01 Regulation FD**

PG&E Corporation, the parent company of Pacific Gas and Electric Company (Utility), intends to provide an update regarding its assessment (described in Item 8.01 below) of the 2017 Northern California wildfires prior to the release of PG&E Corporation and the Utility's financial results for the quarter ending June 30, 2018.

The information included in this Item 7.01 is being furnished, and shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

**Item 8.01 Other Events**

**2017 Northern California Wildfires**

As previously reported, beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada and Yuba Counties, as well as in the area surrounding Yuba City (the "Northern California wildfires"). According to the California Department of Forestry and Fire Protection (CAL FIRE) California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in Northern California that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The wildfires also resulted in 44 fatalities.

On June 8, 2018, CAL FIRE issued a news release announcing the results of its investigation into 12 of the wildfires that occurred last October in Northern California: the Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket and Atlas fires, located in Mendocino, Lake, Butte, Sonoma, Humboldt and Napa counties. According to the CAL FIRE news release:

- "The Redwood Fire, in Mendocino County, started the evening of Oct. 8 and burned a total of 36,523 acres, destroying 543 structures. There were nine civilian fatalities and no injuries to firefighters. CAL FIRE has determined the fire started in two locations and was caused by tree or parts of trees falling onto PG&E power lines.
- The Sulphur Fire, in Lake County, started the evening of Oct. 8 and burned a total of 2,207 acres, destroying 162 structures. There were no injuries. CAL FIRE investigators determined the fire was caused by the failure of a PG&E owned power pole, resulting in the power lines and equipment coming in contact with the ground.
- The Cherokee Fire, in Butte County, started the evening of Oct. 8 and burned a total of 8,417 acres, destroying 6 structures. There were no injuries. CAL FIRE investigators have determined the cause of the fire was a result of tree limbs coming into contact with PG&E power lines.
- The 37 Fire, in Sonoma County, started the evening of Oct. 9 and burned a total of 1,660 acres, destroying 3 structures. There were no injuries. CAL FIRE investigators have determined the cause of the fire was electrical and was associated with the PG&E distribution lines in the area.
- The Blue Fire, in Humboldt County, started the afternoon of Oct. 8 and burned a total of 20 acres. There were no injuries. CAL FIRE investigators have determined a PG&E power line conductor separated from a connector, causing the conductor to fall to the ground, starting the fire.
- The Norrbom, Adobe, Partrick, Pythian and Nuns fires were part of a series of fires that merged in Sonoma and Napa counties. These fires started in the late-night hours of Oct. 8 and burned a combined total of 56,556 acres, destroying 1,355 structures. There were three civilian fatalities.
  - CAL FIRE investigators determined the Norrbom Fire was caused by a tree falling and coming in contact with PG&E power lines.

- CAL FIRE investigators determined the Adobe Fire was caused by a eucalyptus tree falling into a PG&E powerline.
- CAL FIRE investigators determined the Partrick Fire was caused by an oak tree falling into PG&E powerlines.
- CAL FIRE investigators determined the Pythian Fire was caused by a downed powerline after PG&E attempted to reenergize the line.
- CAL FIRE investigators determined the Nuns Fire was caused by a broken top of a tree coming in contact with a power line.

- The Pocket Fire, in Sonoma County, started the early morning hours of Oct. 9 and burned a total of 17,357 acres, destroying 6 structures. There were no injuries. CAL FIRE has determined the fire was caused by the top of an oak tree breaking and coming into contact with PG&E power lines.
- The Atlas Fire, in Napa County, started the evening of Oct. 8 and burned a total of 51,624 acres, destroying 783 structures. There were six civilian fatalities. CAL FIRE investigators determined the fire started in two locations. At one location, it was determined a large limb broke from a tree and came into contact with a PG&E power line. At the second location, investigators determined a tree fell into the same line."

Also on June 8, 2018, CAL FIRE released its investigation reports related to the Redwood, Cherokee, 37 and Nuns fires. CAL FIRE has not yet released its investigation reports related to the Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires and indicated in its news release that these investigations have been referred to the appropriate county District Attorney's offices for review "due to evidence of alleged violations of state law." The timing and outcome for resolution of those referrals are uncertain. The timing and outcome of the CAL FIRE investigation into the remaining fires also are uncertain.

As previously disclosed, the Northern California wildfires also are under investigation by the California Public Utilities Commission (CPUC), including the possible role of the Utility's power lines and other facilities. The CPUC's Safety and Enforcement Division (SED) is conducting investigations to assess the compliance of electric and communication facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. The timing and outcome for completion of these investigations are uncertain. The Utility could be subject to material fines or penalties if the CPUC or any law enforcement agency were to bring an enforcement action and determine that the Utility failed to comply with applicable laws and regulations.

As of June 8, 2018, the Utility had received approximately 200 complaints on behalf of at least 2,700 plaintiffs related to the Northern California wildfires. These cases have been coordinated in the San Francisco Superior Court. The coordinated litigation is in the early stages of discovery. The next case management conference is scheduled for July 9, 2018. The litigation pending against the Utility includes multiple theories of liability, including inverse condemnation and negligence. Under inverse condemnation, the Utility could be strictly liable for property damages and attorneys' fees if its equipment was a substantial cause of a fire, even if the Utility followed established inspection and safety rules. The Utility also may be liable for fire suppression costs, personal injury damages, and other damages if the Utility is found to be negligent. Regardless of any conclusions by CAL FIRE, the litigation could take a number of years to resolve.

The Utility is continuing to review the evidence concerning the causes of the Northern California wildfires. The Utility currently does not have access to the evidence collected by CAL FIRE as part of its investigation.

Following accounting rules, the Utility records a liability when a loss is probable and reasonably estimable. Potential liabilities related to the Northern California wildfires depend on various factors, including but not limited to the cause of each fire, contributing factors to the fire (including alternative potential origins and weather and climate issues), the number, size, and type of structures damaged or destroyed, the contents of such structures, and the number and types of trees damaged or destroyed.

Although the Utility's analysis is ongoing regarding the fires that were the subject of the June 8, 2018 and May 25, 2018 CAL FIRE news releases:

- for the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket and Sonoma/Napa merged fires (which include Nuns, Norrbom, Adobe, Partrick and Pythian), based on the current state of the law on inverse condemnation, the information currently available to the Utility, and the CAL FIRE determinations of cause, PG&E Corporation and the Utility currently expect that they will record a significant liability for losses associated with such fires in PG&E Corporation and the Utility's condensed consolidated financial statements to be included in their Form 10-Q for the quarterly period ending June 30, 2018 (the "Q2 financial statements"); and
- for the Atlas and Highway 37 fires, PG&E Corporation and the Utility do not believe a loss is probable at this time, given the information currently available. However, it is reasonably possible that facts could emerge that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in the accrual of a liability in the future, the amount of which could be significant.

This analysis does not address the Tubbs, Cascade or other fires, for which CAL FIRE has neither announced its determination of the causes nor made available the evidence on which its determinations may be based.

The financial statements of PG&E Corporation and the Utility for the quarterly period ending June 30, 2018 have not yet been prepared. Because the foregoing information relating to the Q2 financial statements is preliminary, it may change and may not be indicative of actual results for the financial quarter.

The assessment of whether a loss is probable, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. In accordance with generally accepted accounting principles, PG&E Corporation and the Utility will evaluate the range of reasonably estimated losses and record a charge based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The process for estimating losses associated with such fires, as well as the process for estimating any available recoveries associated therewith, including insurance recovery, requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, management estimates and assumptions regarding the financial impact of these wildfires may result in material increases to the loss accrued. This estimation process is currently occurring and PG&E Corporation and the Utility currently expect to disclose an estimated accrual prior to the public release of their results for the quarterly period ending June 30, 2018.

Also on June 8, 2018, the Utility issued a news release related to the June 8, 2018 CAL FIRE announcement and investigation reports, which news release is attached as Exhibit 99.1 to this report and incorporated herein.

For additional information about the Northern California wildfires, see PG&E Corporation and the Utility's annual report on Form 10-K for the year ended December 31, 2017, their quarterly report for the quarter ended March 31, 2018, their current report on Form 8-K dated May 25, 2018, and their subsequent reports filed with the Securities and Exchange Commission.

**Item 9.01 Financial Statements and Exhibits**

(d) Exhibits

| | |
|---|---|
| Exhibit 99.1 | Pacific Gas and Electric Company News Release dated June 8, 2018 |

**Cautionary Statement Concerning Forward-Looking Statements**

This current report on Form 8-K and its exhibit include forward-looking statements that are not historical facts, including statements about the beliefs, expectations, estimates, future plans and strategies of PG&E Corporation and the Utility. These statements are based on current expectations and assumptions, which management believes are reasonable, and on information currently available to management, but are necessarily subject to various risks and uncertainties. In addition to the risk that these assumptions prove to be inaccurate, other factors that could cause actual results to differ materially from those contemplated by the forward-looking statements include factors disclosed in PG&E Corporation and the Utility's annual report on Form 10-K for the year ended December 31, 2017, their quarterly report for the quarter ended March 31, 2018, and their subsequent reports filed with the Securities and Exchange Commission.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

**PG&E CORPORATION**

Dated: June 11, 2018

By: /s/ Jason P. Wells
JASON P. WELLS
Senior Vice President and Chief Financial Officer

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: June 11, 2018

By: /s/ David S. Thomason
DAVID S. THOMASON
Vice President, Chief Financial Officer and Controller

Together, Building
a Better California

Marketing & Communications | 77 Beale Street | San Francisco, CA 94105 | 415.973.5930 | www.pge.com

**June 8, 2018**

**PG&E Responds to Latest CAL FIRE Announcement**

**SAN FRANCISCO, Calif.** —Pacific Gas and Electric Company (PG&E) today issued the following statement in response to the latest release of information by the California Department of Forestry and Fire Protection (CAL FIRE) regarding some of the October 2017 Northern California wildfires:

The safety of our customers, their families and the communities we serve is our most important job. The loss of life, homes and businesses in these extraordinary wildfires is simply heartbreaking, and we remain focused on helping communities recover and rebuild.

**Programs Overall Met State's High Standards**

We look forward to the opportunity to carefully review the CAL FIRE reports to understand the agency's perspectives.

Based on the information we have so far, we continue to believe our overall programs met our state's high standards.

For example, PG&E meets or exceeds regulatory requirements for pole integrity management, using a comprehensive database to manage multiple patrol and inspection schedules of our more than two million poles.

Similarly, under PG&E's industry-leading Vegetation Management Program, we inspect and monitor every PG&E overhead electric transmission and distribution line each year, with some locations patrolled multiple times. We also prune or remove approximately 1.4 million trees annually.

Following Governor Brown's January 2014 Drought State of Emergency Proclamation and the California Public Utilities Commission's Resolution ESRB-4, PG&E added enhanced measures to address areas particularly affected by drought and bark beetles including increased foot and aerial patrols along power lines in high fire-risk areas, removal of hundreds of thousands of dead or dying trees, and daily aerial fire detection patrols during high fire season to improve fire spotting and speed of fire response.

**'New Normal' Requires New Solutions**

With that said, years of drought, extreme heat and 129 million dead trees have created a "new normal" for our state that requires comprehensive new solutions.

Extreme weather is increasing the number of large wildfires and the length of the wildfire season in California. According to CAL FIRE, in 2017 alone, CAL FIRE confronted 7,117 wildfires, compared to an average of 4,835 during the preceding five years. Five of the 20 most destructive wildfires in the state's history burned between October and December 2017.

In the case of these Northern California wildfires, we saw an unprecedented confluence of weather-related conditions, including: years of drought resulting in millions of dead trees, a record-setting wet winter that spurred the growth of vegetation that then became abundant fuel after record-setting heat during the summer months, very low humidity and very high winds.

To address the growing threats posed by wildfires and extreme weather, and in light of the wildfires throughout our state last year, PG&E has launched the Community Wildfire Safety Program to help keep our customers and communities safe. Among the key components of the new program are:

- Wildfire Safety Operations Center: A state of the art operations center that will monitor extreme weather and fire threats in real time and in coordination with our safety partners.
- Weather Stations Network: A network of weather stations throughout high fire-risk areas to better monitor growing extreme weather conditions and predict where wildfires may occur.
- Fire Defense Zones: Augmenting our already rigorous vegetation management program to create new fire defense zones near power lines in high fire threat areas.
- Public Safety Power Shutoff: As a last resort, a program to proactively turn off electric power for safety when extreme fire danger conditions occur, while helping customers prepare and providing early warning notification, when and where possible.

**We Must Work Together to Address This Challenge**

The state, first responders and California's utilities are all in agreement that we must work together to prevent and respond to wildfires and enhance infrastructure resiliency.

This includes solutions that go beyond utility practices such as improvements in forestry management and in building codes. In addition, we must address the availability and affordability of insurance coverage, and we believe it is imperative to reform California's unsustainable policies regarding wildfire liability.

California is one of the only states in the country where the courts have applied inverse condemnation liability to events associated with investor-owned utility equipment. This means PG&E could be liable for property damages and attorneys' fees even if we followed established inspection and safety rules.

Liability regardless of negligence undermines the financial health of the state's utilities, discourages investment in California and has the potential to materially impact the ability of utilities to access the capital markets to fund utility operations and California's bold clean energy vision.

Reforming inverse condemnation would not absolve utilities from responsibility. Anyone harmed by these tragic wildfires has the ability to pursue a negligence claim in court. Furthermore, the CPUC, which regulates utilities, has the authority to investigate and evaluate a company's conduct and performance and deny the recovery of costs if such conduct did not meet the state's high standards.

We are committed to advocating with legislative leaders and policymakers across the state on comprehensive legislative solutions for all Californians, as we collectively seek to meet the challenge of climate change, and position the California economy for success.

**About PG&E**

Pacific Gas and Electric Company, a subsidiary of PG&E Corporation (NYSE:PCG), is one of the largest combined natural gas and electric energy companies in the United States. Based in San Francisco, with more than 20,000 employees, the company delivers some of the nation's cleanest energy to nearly 16 million people in Northern and Central California. For more information, visit www.pge.com/ and pge.com/news.

CURRENTS | | | |

# Exhibit 17

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K

**CURRENT REPORT**
**Pursuant to Section 13 or 15(d)**
**of the Securities Exchange Act of 1934**

**Date of Report: June 21, 2018 (Date of earliest event reported)**

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

| PG&E Corporation | Pacific Gas and Electric Company |
|---|---|
| 77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177<br>(Address of principal executive offices) (Zip Code) | 77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177<br>(Address of principal executive offices) (Zip Code) |
| (415) 973-1000<br>(Registrant's telephone number, including area code) | (415) 973-7000<br>(Registrant's telephone number, including area code) |

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 8.01 Other Events**

**2017 Northern California Wildfires**

As previously reported, beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada and Yuba Counties, as well as in the area surrounding Yuba City (the "Northern California wildfires"). According to the California Department of Forestry and Fire Protection ("CAL FIRE") California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in Northern California that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The wildfires also resulted in 44 fatalities.

As previously disclosed, on May 25, 2018, CAL FIRE issued a news release announcing its determination on the causes of four of the Northern California wildfires (the La Porte, McCourtney, Lobo and Honey fires located in Butte and Nevada Counties) and, on June 8, 2018, CAL FIRE issued a news release announcing its determination on the causes of twelve additional Northern California wildfires (the Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket and Atlas fires, located in Mendocino, Lake, Butte, Sonoma, Humboldt and Napa counties). CAL FIRE has not issued any news releases or other determinations for the Tubbs, Cascade, Maacama, Pressley and Point wildfires.

As of June 18, 2018, PG&E Corporation and Pacific Gas and Electric Company (the "Utility") had received approximately 200 complaints on behalf of at least 2,700 plaintiffs related to the Northern California wildfires. These cases have been coordinated in the San Francisco Superior Court. The coordinated litigation is in the early stages of discovery. The next case management conference is scheduled for July 9, 2018.

The litigation pending against PG&E Corporation and the Utility includes claims under multiple theories of liability, including inverse condemnation and negligence. Under the doctrine of inverse condemnation, the Utility could be strictly liable for property damages and attorneys' fees if its equipment was a substantial cause of a fire, even if the Utility followed established inspection and safety rules. The Utility also may be liable for fire suppression and clean-up costs, personal injury damages, and other damages if the Utility is found to be negligent, and the Utility could be subject to material fines or penalties if the California Public Utilities Commission or any law enforcement agency were to bring an enforcement action and determine that the Utility failed to comply with applicable laws and regulations. PG&E Corporation or the Utility also could be the subject of investigations or other actions by the county District Attorneys to whom CAL FIRE has referred its investigations into the McCourtney, Lobo, Honey, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires. Regardless of any determinations of cause by CAL FIRE, ultimately PG&E Corporation and the Utility's liability will be resolved through litigation, regulatory and any potential enforcement proceedings, which could take a number of years to resolve. The timing and outcome of these and other potential proceedings are uncertain.

PG&E Corporation and the Utility are continuing to review the evidence concerning the causes of the Northern California wildfires. PG&E Corporation and the Utility currently do not have access to the evidence collected by CAL FIRE as part of its investigation or to the investigation reports for the fires CAL FIRE has referred to the county District Attorneys.

Following accounting rules, PG&E Corporation and the Utility record a liability when a loss is probable and reasonably estimable. Potential liabilities related to the Northern California wildfires depend on various factors, including but not limited to the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties or fines that may be imposed by governmental entities. In accordance with U.S. generally accepted accounting principles, PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses, and record a charge that is the amount within the range that is a better estimate than any other amount or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events.

In light of the current state of the law on inverse condemnation and the information currently available to the Utility including, among other things, the CAL FIRE determinations of cause, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with fourteen of the Northern California wildfires referred to as the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket and Sonoma/Napa merged fires (which include the Nuns, Norrbom, Adobe, Partrick and Pythian fires), and accordingly PG&E Corporation and the Utility intend to record an estimated pre-tax charge in the amount of $2.5 billion for the quarter ending June 30, 2018 ($1.8 billion after-tax). This expected charge corresponds to the lower end of the range of PG&E Corporation and the Utility's reasonably estimated losses, and is subject to change based on additional information, which change could occur prior to the filing of PG&E Corporation and the Utility's Quarterly Report on Form 10-Q for the period ending June 30, 2018 (the "Form 10-Q"). PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss will be greater than the amount accrued and are unable to reasonably estimate the additional loss and the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in CAL FIRE's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

The process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with similar fires. As more information becomes available, management estimates and assumptions regarding the financial impact of the Northern California wildfires may change, which could result in material increases to the loss accrued.

The expected $2.5 billion pre-tax charge does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility. It also does not include any amounts in connection with any of the other Northern California wildfires (including the Atlas, 37, Tubbs, Cascade, Maacama, Pressley and Point fires) because at this time PG&E Corporation and the Utility have concluded that a loss arising from those fires is not probable. However, in the future it is possible that facts could emerge that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in the accrual of a liability at that time, the amount of which could be significant.

As previously reported, on January 31, 2018, the California Department of Insurance issued a news release announcing an update on property losses in connection with the October and December 2017 wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the Northern California wildfires. That news release reflected insured property losses only. Additionally, that amount did not account for uninsured losses, interest, attorneys' fees, fire suppression and clean-up costs, personal injury and wrongful death damages or other costs. If PG&E Corporation and the Utility were to be found liable for certain or all of such other costs and expenses, including the potential liabilities outlined above, the amount of the liability could significantly exceed the approximately $10 billion in estimated insured property losses with respect to the Northern California wildfires.

PG&E Corporation and the Utility have liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $840 million, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. In addition, coverage limits within these wildfire insurance policies could result in further material self-insured costs in the event each fire were deemed to be a separate occurrence under the terms of the insurance policies.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. PG&E Corporation and the Utility currently expect to record $375 million ($270 million after-tax) for probable insurance recoveries in connection with the Northern California wildfires for the quarter ending June 30, 2018. This amount reflects an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. The amount of the expected receivable is also subject to change based on additional information, which change could occur prior to the filing of the Form 10-Q. PG&E Corporation and the Utility intend to seek full recovery for all insured losses and believe it is reasonably possible that they will record a receivable for the full amount of the insurance limits in the future. If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's

financial condition, results of operations, or cash flows could be materially affected. Even if PG&E Corporation and the Utility were to recover the full amount of their insurance, the potential losses arising out of the Northern California wildfires could significantly exceed the coverage limits of the insurance.

In addition, it could take a number of years before the Utility's final liability is known and the Utility could apply for cost recovery. The Utility may be unable to fully recover costs in excess of insurance through regulatory mechanisms, if at all, and, even if such recovery is possible, it could take a number of years to resolve and a number of years to collect. PG&E Corporation and the Utility have considered actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, capital markets access and cash flows.

Finally, the CPUC's capital structure decisions require the Utility to maintain a minimum 51% equity ratio at all times and a minimum 52% average equity ratio over the period that the authorized capital structure is in place. The Utility currently does not anticipate that net charges that the Utility intends to record in connection with the Northern California wildfires for the quarter ending June 30, 2018, and described herein, will result in noncompliance by the Utility with its authorized capital structure. However, in the future, maintaining compliance with the Utility's authorized capital structure may require PG&E Corporation to issue a significant amount of equity, depending on the timing and amount of any claims payments and whether additional charges are recorded. The Utility also may submit to the CPUC an application for a waiver to its capital structure condition if its equity ratio were to fall below the minimum levels. However, there can be no assurance that the CPUC ultimately would grant any such waiver.

For additional information about the Northern California wildfires, see PG&E Corporation and the Utility's annual report on Form 10-K for the year ended December 31, 2017, their quarterly report for the quarter ended March 31, 2018, their current reports on Form 8-K dated May 29, 2018 and June 8, 2018, and their subsequent reports filed with the Securities and Exchange Commission.

**Cautionary Statement Concerning Forward-Looking Statements**

This current report on Form 8-K includes forward-looking statements that are not historical facts, including statements about the beliefs, expectations, estimates, future plans and strategies of PG&E Corporation and the Utility. These statements are based on current expectations and assumptions, which management believes are reasonable, and on information currently available to management, but are necessarily subject to various risks and uncertainties. In addition to the risk that these assumptions prove to be inaccurate, other factors that could cause actual results to differ materially from those contemplated by the forward-looking statements include factors disclosed in PG&E Corporation and the Utility's annual report on Form 10-K for the year ended December 31, 2017, their quarterly report for the quarter ended March 31, 2018, and their subsequent reports filed with the Securities and Exchange Commission.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

**PG&E CORPORATION**

Dated: June 21, 2018

By: /s/ Jason P. Wells
Jason P. Wells
Senior Vice President and Chief Financial Officer

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: June 21, 2018

By: /s/ David S. Thomason
David S. Thomason
Vice President, Chief Financial Officer and Controller

# Exhibit 18

UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

# FORM 8-K

**CURRENT REPORT**

**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**Date of Report: November 9, 2018**
(Date of earliest event reported)

| Commission File Number | Exact Name of Registrant as specified in its charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |

PG&E Corporation.

**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company

**77 Beale Street**
**P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

| | | |
|---|---|---|
| Emerging growth company | PG&E Corporation | ☐ |
| Emerging growth company | Pacific Gas and Electric Company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation | ☐ |
| Pacific Gas and Electric Company | ☐ |

**Item 2.03. Creation of a Direct Financial Obligation or an Obligation Under an Off-Balance Sheet Arrangement of a Registrant.**

As of November 13, 2018, Pacific Gas and Electric Company ("Utility"), a subsidiary of PG&E Corporation, and PG&E Corporation have aggregate borrowings outstanding under their respective revolving credit facilities of $3.0 billion and $300 million, respectively. The Utility's aggregate borrowings under its revolving credit facility includes $2.85 billion of revolving credit loans, approximately $105 million of letters of credit outstanding, and $10 million of commercial paper. No additional amounts are available under the Utility's and PG&E Corporation's respective revolving credit facilities.

With these borrowings, PG&E Corporation's and the Utility's balance of cash and cash equivalents increased to approximately $356 million and $3.1 billion, respectively, at November 13, 2018. PG&E Corporation and the Utility made the borrowings under their respective revolving credit facilities for greater financial flexibility. PG&E Corporation and the Utility plan to invest the cash proceeds from the borrowings in highly liquid short-term investments and to use them for general corporate purposes, including upcoming debt maturities.

Any description of PG&E Corporation's or the Utility's respective credit agreements is qualified in its entirety by reference to the complete copies of PG&E Corporation's and the Utility's credit agreements filed as Exhibits 10.1 and 10.2, respectively, to PG&E Corporation and the Utility's Form 10-Q for the quarter ended March 31, 2015, which credit agreements are incorporated by reference herein.

**Item 8.01 Other Events.**

***Camp Fire***

On November 8, 2018, a wildfire began near the city of Paradise, Butte County, California (the "Camp Fire"), located in the service territory of the Utility. The California Department of Forestry and Fire Protection's ("Cal Fire") Camp Fire Incident Report dated November 13, 2018, 7:00 a.m. Pacific Time (the "incident report"), indicated that the Camp Fire had consumed 125,000 acres and was 30% contained. Cal Fire estimates in the incident report that the Camp Fire will be fully contained on November 30, 2018. In the incident report, Cal Fire reported 42 fatalities. The incident report also indicates the following: structures threatened, 15,500; single residences destroyed, 6,522; single residences damaged, 75; multiple residences destroyed, 85; commercial structures destroyed, 260; commercial structures damaged, 32; and other minor structures destroyed, 772.

The cause of the Camp Fire is under investigation. On November 8, 2018, the Utility submitted an electric incident report to the California Public Utilities Commission (the "CPUC") indicating that "on November 8, 2018 at approximately 0615 hours, PG&E experienced an outage on the Caribou-Palermo 115 kV Transmission line in Butte County. In the afternoon of November 8, PG&E observed by aerial patrol damage to a transmission tower on the Caribou-Palermo 115 kV Transmission line, approximately one mile north-east of the town of Pulga, in the area of the Camp Fire. This information is preliminary." Also on November 8, 2018, acting governor Gavin Newsom issued an emergency proclamation for Butte County, due to the effect of the Camp Fire.

As previously reported, during the third quarter of 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019. For more information about wildfire insurance and risks associated with wildfires, see PG&E Corporation and the Utility's quarterly report on Form 10-Q for the quarter ended September 30, 2018.

While the cause of the Camp Fire is still under investigation, if the Utility's equipment is determined to be the cause, the Utility could be subject to significant liability in excess of insurance coverage that would be expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

**Cautionary Statement Concerning Forward-Looking Statements**

This current report on Form 8-K includes forward-looking statements that are not historical facts, including statements about the beliefs, expectations, estimates, future plans and strategies of PG&E Corporation and the Utility. These statements are based on current expectations and assumptions, which management believes are reasonable, and on information currently available to management, but are necessarily subject to various risks and uncertainties. In addition to the risk that these assumptions prove to be inaccurate, other factors that could cause actual results to differ materially from those contemplated by the forward-looking statements include factors disclosed in PG&E Corporation and the Utility's annual report on Form 10-K for the year ended December 31, 2017, their quarterly reports for the quarters ended March 31, 2018, June 30, 2018 and September 30, 2018, and their subsequent reports filed with the Securities and Exchange Commission.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

**PG&E CORPORATION**

Dated: November 13, 2018

By: /s/ LINDA Y.H. CHENG
LINDA Y.H. CHENG
Vice President, Corporate Governance and
Corporate Secretary

**PACIFIC GAS AND ELECTRIC COMPANY**

Dated: November 13, 2018

By: /s/ DAVID S. THOMASON
DAVID S. THOMASON
Vice President, Chief Financial Officer and Controller

# Exhibit 19

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**Filed Pursuant to Rule 424(b)(2)**
**Registration No. 333-193879**

# CALCULATION OF REGISTRATION FEE

| Title of each Class of Securities to be Registered | Maximum Aggregate Offering Price | Amount of Registration Fee(1) |
|---|---|---|
| Debt Securities | $600,000,000 | $60,420 |

(1) Calculated in accordance with Rule 457(r) under the Securities Act of 1933, as amended

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**PROSPECTUS SUPPLEMENT**
**(To Prospectus dated February 11, 2014)**

# $600,000,000
# 2.95% Senior Notes due March 1, 2026

We are offering $600,000,000 principal amount of our 2.95% Senior Notes due March 1, 2026, which we refer to in this prospectus supplement as our "senior notes."

We will pay interest on our senior notes offered hereby on each March 1 and September 1, commencing September 1, 2016. The senior notes will be issued in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

We may redeem the senior notes in whole or in part at any time at the redemption prices set forth in this prospectus supplement.

The senior notes will be unsecured and will rank equally with all of our other unsecured and unsubordinated indebtedness from time to time outstanding.

There is no existing public market for the senior notes. We do not intend to apply to list the senior notes on any securities exchange or any automated quotation system.

**Investing in these senior notes involves risks. See "Risk Factors" on page S-1 of this prospectus supplement.**

| | Per Senior Note | Total |
|---|---|---|
| Public Offering Price[1] | 99.734% | $598,404,000 |
| Underwriting Discounts and Commissions | 0.650% | $ 3,900,000 |
| Proceeds to Pacific Gas and Electric Company (before expenses)[1] | 99.084% | $594,504,000 |

(1) Plus accrued interest, if any, from and including original issuance of the senior notes which is expected to be March 1, 2016.

**None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus supplement or the accompanying prospectus. Any representation to the contrary is a criminal offense.**

The senior notes are expected to be delivered on or about March 1, 2016 through the book-entry facilities of The Depository Trust Company for the accounts of its participants, including Clearstream Banking, société anonyme, and Euroclear Bank S.A./N.V.

*Joint Book-Running Managers*

**Barclays** **BNP PARIBAS** **Morgan Stanley** **MUFG** **The Williams Capital Group, L.P.**

*Co-Managers*

**BNY Mellon Capital Markets, LLC** **TD Securities**

**C.L. King & Associates** **Great Pacific Securities**

February 23, 2016

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**This prospectus supplement should be read in conjunction with the accompanying prospectus. You should rely only on the information contained in this prospectus supplement, the accompanying prospectus, the information incorporated by reference into this prospectus supplement and the accompanying prospectus and any free writing prospectus prepared by us. Neither we nor any underwriter has authorized any other person to provide you with different or additional information. If anyone provides you with different or additional information, you should not rely on it. Neither we nor any underwriter is making an offer to sell the senior notes in any jurisdiction where the offer or sale is not permitted. You should assume that the information contained in or incorporated by reference in this prospectus supplement, the accompanying prospectus and any free writing prospectus prepared by us is accurate only as of the date of the document containing the information or such other date as may be specified therein.**

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Unless otherwise indicated, when used in this prospectus supplement and the accompanying prospectus, the terms “we,” “our” and “us” refer to Pacific Gas and Electric Company and its subsidiaries, and the term “Corp” refers to our parent, PG&E Corporation.

## RISK FACTORS

Investing in the senior notes involves risk. These risks are described under "Risk Factors" in Item 1A of our annual report on Form 10-K for the fiscal year ended December 31, 2015, which is incorporated by reference in this prospectus supplement and the accompanying prospectus. See "Where You Can Find More Information" in the accompanying prospectus. Before making a decision to invest in the senior notes, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus.

## FORWARD-LOOKING STATEMENTS

This prospectus supplement, the accompanying prospectus and any documents incorporated by reference into this prospectus supplement and the accompanying prospectus contain forward-looking statements. These statements are subject to various risks and uncertainties, the realization or resolution of which may be outside of management's control. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this prospectus supplement.

These forward-looking statements relate to, among other matters, estimated costs, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that we will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the 2015 gas transmission and storage ("GT&S") rate case, the 2017 general rate case, the transmission owner rate cases, and other ratemaking and regulatory proceedings;
- the timing and outcomes of the federal criminal prosecution of us, the pending California Public Utilities Commission ("CPUC") investigation of our natural gas distribution record-keeping practices, the Safety and Enforcement Division's unresolved enforcement matters relating to our compliance with natural gas-related laws and regulations, and the other investigations that have been or may be commenced relating to the our compliance with natural gas-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that we may incur in connection with the outcomes;
- the timing and outcome of the CPUC's investigation of communications between us and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other ratemaking proceedings;
- whether we are able to repair the harm to our reputation caused by the criminal prosecution of us, the state and federal investigations of natural gas incidents, matters relating to the indicted case, improper communications between the CPUC and us; and our ongoing work to remove encroachments from transmission pipeline rights-of-way;
- whether we can control our costs within the authorized levels of spending, the extent to which we incur unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- the outcome of the CPUC's investigation into our safety culture, and future legislative or regulatory actions that may be taken to require us to separate our electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;
- the outcomes of future investigations or other enforcement proceedings that may be commenced relating to our compliance with laws, rules, regulations, or orders applicable to our operations, including the construction, expansion or replacement of our electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge our known and unknown remediation obligations; and the extent to which we are able to recover environmental costs in rates or from other sources;
- the ultimate amount of unrecoverable environmental costs we incur associated with our natural gas compressor station site located near Hinkley, California;
- the impact of new legislation or Nuclear Regulatory Commission regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies, including the California State Water Resources Board and the California State Lands Commission, that may affect our ability to continue operating Diablo Canyon; and whether we decide to resume our pursuit to renew the two Diablo Canyon NRC operating licenses, and if so, whether the licenses are renewed;
- the impact of droughts or other weather-related conditions or events, wildfires (including the Butte fire in September 2015, which affected portions of Amador and Calaveras counties), climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the our service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by us, our customers, or third parties on which we rely; whether we incur liability to third parties for property damage or personal injury caused by such events; and whether the we are subject to civil, criminal, or regulatory penalties in connection with such events;
- how the CPUC and the California Air Resources Board implement state environmental laws relating to greenhouse gases, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether we are able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations, and whether we are able to timely recover our associated investment costs;
- whether our climate change adaptation strategies are successful;
- the impact that reductions in customer demand for electricity and natural gas have on our ability to make and recover our investments through rates and earn our authorized return on equity, and whether our business strategy to address the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services is successful;
- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which we can manage and respond to the volatility of energy commodity prices; our ability and the ability of our counterparties to post or return collateral in connection with price risk management activities; and whether we are able to recover timely our electric generation and energy commodity costs through rates, including our renewable energy procurement costs;
- whether our information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether we are able to protect our operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether our security measures are sufficient to protect against unauthorized

or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether we can continue to rely on third-party vendors and contractors that maintain and support some of our information technology and operating systems;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether we can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;
- our ability to access capital markets and other sources of financing in a timely manner on acceptable terms;
- changes in credit ratings which could result in increased borrowing costs especially if we were to lose our investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and
- the impact of changes in U.S. Generally Accepted Accounting Principles, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and our future financial condition, results of operations and cash flows, you should read the sections titled “Risk Factors” in the documents incorporated by reference in this prospectus supplement and the accompanying prospectus, together with “Risk Factors” in this prospectus supplement.

You should read this prospectus supplement, the accompanying prospectus and the documents that we incorporate by reference into this prospectus supplement and the accompanying prospectus, the documents that we have included as exhibits to the registration statement of which this prospectus supplement and the accompanying prospectus are a part and the documents that we refer to under the section of the accompanying prospectus titled “Where You Can Find More Information” completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statements. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus supplement or the date of the document incorporated by reference. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

## OUR COMPANY

We are one of the largest combination natural gas and electric utilities in the United States. We were incorporated in California in 1905 and are a subsidiary of PG&E Corporation. We provide natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers. The principal executive offices of PG&E Corporation and Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and the telephone number of Pacific Gas and Electric Company is (415) 973-7000.

## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our historical ratio of earnings to fixed charges for each of the fiscal years indicated.

| 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|
| 1.67x | 2.55x | 2.23x | 2.24x | 2.51x |

For the purpose of computing our ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, allowance for funds used during construction debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

## USE OF PROCEEDS

We estimate that the net proceeds from this offering will be approximately $593.2 million, after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We expect to use the net proceeds from the offering for general corporate purposes, including to repay our outstanding commercial paper. At February 22, 2016, the outstanding commercial paper was approximately $938.5 million, the weighted average yield on our outstanding commercial paper was approximately 0.6% per annum and the weighted average maturity on our outstanding commercial paper was 16.8 days.

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## CAPITALIZATION

The following table sets forth our consolidated capitalization as of December 31, 2015, as adjusted to give effect to (i) the issuance and sale of the senior notes, and (ii) the use of net proceeds from this offering as set forth under "Use of Proceeds" in this prospectus supplement. This table should be read in conjunction with our consolidated financial statements and related notes as of and for the fiscal year ended December 31, 2015, incorporated by reference in this prospectus supplement and the accompanying prospectus. See "Where You Can Find More Information" in the accompanying prospectus.

| | As of December 31, 2015 | |
|---|---|---|
| | Actual | As Adjusted |
| | (in millions) | |
| Current Liabilities: | | |
| Short-term borrowings(1) | $ 1,019 | $ 426 |
| Total long-term debt classified as current | $ 160 | $ 160 |
| Capitalization: | | |
| Long-term debt(2) | $15,680 | $ 16,278 |
| Shareholders' equity(3) | 17,060 | 17,060 |
| Total capitalization | $32,740 | $ 33,338 |

(1) Actual short-term borrowings primarily included commercial paper and as adjusted short-term borrowings gives effect to the use of proceeds of this offering to repay our outstanding commercial paper.

(2) Actual long-term debt consisted of $1,108 million of pollution control bonds and $14,572 million of senior notes and as adjusted long-term debt includes the senior notes offered hereby, in each case, net of any discounts and premiums.

(3) Includes $258 million of preferred stock without mandatory redemption provisions.

## DESCRIPTION OF THE SENIOR NOTES

### General

You should read the following information in conjunction with the statements under “Description of the Senior Notes” in the accompanying prospectus.

As used in this section, the terms “we,” “us” and “our” refer to Pacific Gas and Electric Company, and not to any of our subsidiaries.

The senior notes are being offered in the aggregate principal amount of $600,000,000 and will mature on March 1, 2026.

We will issue the senior notes under an existing indenture, which was originally entered into on March 11, 2004 and amended and restated on April 22, 2005, between us and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A.), as trustee, as supplemented by supplemental indentures between us and the trustee. Please read the indenture because it, and not this description, defines your rights as holders of the senior notes. We have filed with the Securities and Exchange Commission a copy of the indenture as an exhibit to the registration statement of which this prospectus supplement and the accompanying prospectus are a part.

Pursuant to the Trust Indenture Act of 1939, as amended, or the 1939 Act, if a default occurs on the senior notes, The Bank of New York Mellon Trust Company, N.A. may be required to resign as trustee under the indenture if it has a conflicting interest (as defined in the 1939 Act), unless the default is cured, duly waived or otherwise eliminated within 90 days.

We may, without consent of the holders of senior notes, issue additional notes under the indenture, having the same terms in all respects to the senior notes (except for the public offering price and the issue date and, in some cases, the first interest payment date) so that those additional notes will be consolidated and form a single series with the other outstanding senior notes.

The senior notes will bear interest from March 1, 2016 at 2.95% per annum, payable semiannually on each March 1 and September 1, commencing on September 1, 2016 to holders of record at the close of business on February 15 and August 15 immediately preceding the interest payment date.

We will issue the senior notes in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The senior notes will be redeemable at our option, in whole or in part, at any time as described below under “Optional Redemption for Senior Notes.”

Interest on the senior notes will be computed on the basis of a 360-day year consisting of twelve 30-day months. If any payment date falls on a day that is not a business day, the payment will be made on the next business day, but we will consider that payment as being made on the date that the payment was due to you. In that event, no interest will accrue on the amount payable for the period from and after such payment date to such next business day.

We will issue the senior notes in the form of one or more global securities, which will be deposited with, or on behalf of, The Depository Trust Company, or DTC, and registered in the name of DTC’s nominee. Information regarding DTC’s book-entry system is set forth below under “Book-Entry System; Global Notes.”

### Ranking

The senior notes will be our direct, unsecured and unsubordinated obligations and will rank equally with all our other existing and future unsecured and unsubordinated obligations. The senior notes will be effectively

subordinated to all our secured debt. As of December 31, 2015, we had approximately $14.7 billion of notes outstanding under the indenture for senior notes. The indenture contains no restrictions on the amount of additional indebtedness that may be incurred by us.

As of December 31, 2015, we did not have any outstanding secured debt for borrowed money.

**Optional Redemption for Senior Notes**

At any time prior to December 1, 2025 (the date that is three months prior to the maturity date), we may, at our option, redeem the senior notes in whole or in part at a redemption price equal to the greater of:

- 100% of the principal amount of the senior notes to be redeemed; or
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the senior notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) calculated as if the maturity date of the senior notes was December 1, 2025 (the date that is three months prior to the maturity date), discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate plus 20 basis points,

plus, in either case, accrued and unpaid interest to, but not including, the redemption date.

At any time on or after December 1, 2025 (the date that is three months prior to the maturity date), we may redeem the senior notes, in whole or in part, at 100% of the principal amount of the senior notes being redeemed plus accrued and unpaid interest to, but not including, the redemption date.

As used in this section "Optional Redemption for Senior Notes," the following terms shall have the following meanings:

"Adjusted Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date.

"Business Day" means any day that is not a day on which banking institutions in New York City are authorized or required by law or regulation to close.

"Comparable Treasury Issue" means the United States Treasury security selected by the applicable Quotation Agent as having a maturity comparable to the remaining term of the senior notes to be redeemed that would be used, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the senior notes to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date:

- the average of the Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest of the Reference Treasury Dealer Quotations; or
- if we obtain fewer than four Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations so received.

"Quotation Agent" means the Reference Treasury Dealer appointed by us for the senior notes.

"Reference Treasury Dealer" means (1) each of Barclays Capital Inc., BNP Paribas Securities Corp. and Morgan Stanley & Co. LLC and their respective successors, unless any of them ceases to be a primary dealer in certain U.S. government securities ("Primary Treasury Dealer"), in which case we shall substitute another Primary Treasury Dealer; and (2) any other Primary Treasury Dealer selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that redemption date.

The redemption price will be calculated assuming a 360-day year consisting of twelve 30-day months.

We will mail notice of any redemption at least 10 days but not more than 60 days before the redemption date to each registered holder of the senior notes to be redeemed.

Unless we default in payment of the redemption price, on and after the redemption date, interest will cease to accrue on the senior notes or portions of the senior notes called for redemption.

If we redeem only some of the senior notes, DTC's practice is to choose by lot the amount to be redeemed from the senior notes held by each of its participating institutions. DTC will give notice to these participants, and these participants will give notice to any "street name" holders of any indirect interests in the senior notes to be redeemed according to arrangements among them. These notices may be subject to statutory or regulatory requirements. We will not be responsible for giving notice of a redemption of the senior notes to be redeemed to anyone other than the registered holders of the senior notes to be redeemed, which is currently DTC. If senior notes to be redeemed are no longer held through DTC and fewer than all the senior notes are to be redeemed, selection of senior notes for redemption will be made by the trustee in any manner the trustee deems fair and appropriate.

Subject to the foregoing and to applicable law (including, without limitation, United States federal securities laws), we or our affiliates may, at any time and from time to time, purchase outstanding senior notes by tender, in the open market or by private agreement.

**No Sinking Fund**

There is no provision for a sinking fund for the senior notes.

**Covenants**

The indenture restricts us and any of our subsidiaries which are "significant subsidiaries" from incurring or assuming secured debt or entering into sale and leaseback transactions, except in certain circumstances. The accompanying prospectus describes this covenant (see "Description of the Senior Notes—Restrictions on Liens and Sale and Leaseback Transactions" in the accompanying prospectus) and other covenants contained in the indenture in greater detail and should be read prior to investing.

**Book-Entry System; Global Notes**

The senior notes will initially be issued in the form of one or more global notes. The senior notes will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered security certificate will be issued for the senior notes in the aggregate principal amount of the senior notes, and will be deposited with DTC or the trustee on behalf of DTC and registered in the name of DTC or its nominee. If, however, the aggregate principal amount of the senior notes exceeds $500 million, one certificate will be issued with respect to each $500 million of principal amount and an additional certificate will be issued with respect to any remaining principal amount of senior notes. Investors may hold their beneficial interests in a global note directly through DTC or indirectly through organizations which are participants in the DTC system.

## CERTAIN UNITED STATES FEDERAL INCOME TAX CONSEQUENCES

The following summary describes certain United States federal income tax consequences of the acquisition, ownership and disposition of the senior notes as of the date hereof. This summary is based on the Internal Revenue Code of 1986, as amended, as well as final, temporary and proposed Treasury regulations and administrative and judicial decisions. Legislative, judicial and administrative changes may occur, possibly with retroactive effect, that could affect the accuracy of the statements described herein. This summary generally is addressed only to original purchasers of the senior notes that purchase the senior notes at the initial offering price, deals only with senior notes held as capital assets and does not purport to address all United States federal income tax matters that may be relevant to investors in special tax situations, such as insurance companies, tax-exempt organizations, financial institutions, dealers in securities or currencies, traders in securities that elect to mark to market, holders of senior notes that are held as a hedge or as part of a hedging, straddle or conversion transaction, certain former citizens or residents of the United States, or United States holders (as defined below) whose functional currency is not the United States dollar. **Persons considering the purchase of the senior notes should consult their own tax advisors concerning the application of United States federal income tax laws, as well as the laws of any state, local or foreign taxing jurisdictions, to their particular situations.**

If a partnership (including an entity treated as a partnership for United States federal income tax purposes) is a beneficial owner of a senior note, the treatment of such partnership, or a partner in the partnership, will generally depend upon the status of the partner and upon the activities of the partnership. A beneficial owner of a senior note that is a partnership, and partners in such a partnership, should consult their tax advisors about the United States federal income tax consequences of holding and disposing of the senior notes.

### United States Holders

This section describes the tax consequences to a United States holder. A "United States holder" is a beneficial owner of a senior note that is (i) a citizen or resident of the United States, (ii) a corporation (including an entity treated as a corporation for United States federal income tax purposes) created or organized in the United States or any state (including the District of Columbia), (iii) an estate whose income is subject to United States federal income tax on a net income basis in respect of the senior note, or (iv) a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorized to control all substantial decisions of the trust (or certain trusts that have made a valid election to be treated as a United States person).

If you are not a United States holder, this section does not apply to you. See "Non-United States Holders" below.

#### *Payment of Interest*

The senior notes will not be issued with more than a *de minimis* amount of original issue discount for United States federal income tax purposes. Interest on a senior note will therefore be taxable to a United States holder as ordinary interest income at the time it accrues or is received, in accordance with the United States holder's method of accounting for United States federal income tax purposes.

#### *Sale, Exchange or Retirement of Senior Notes*

Upon the sale, exchange or retirement of a senior note, a United States holder will recognize taxable gain or loss equal to the difference between the amount realized from the sale, exchange, retirement or other disposition (other than amounts attributable to accrued interest not previously included in income, which will be taxable as ordinary interest income) and the United States holder's adjusted tax basis in the senior note. A United States holder's adjusted tax basis in a senior note will generally equal the cost of the senior note to such holder increased by the amount of any accrued but unpaid interest previously included in income. Such gain or loss

generally will be capital gain or loss, and will be long-term capital gain or loss if the senior note has been held for more than one year. Capital losses are subject to certain limitations.

### *Tax on Net Investment Income*

Certain non-corporate United States holders of senior notes generally will be subject to a 3.8% tax on their net investment income for the relevant taxable year. Subject to certain exceptions, a United States holder's calculation of its net investment income generally will include its interest income on, and its net gains from the disposition of, the senior notes. A United States holder that is an individual, estate or trust is urged to consult its tax advisor regarding the applicability of this tax to its income and gains in respect of your investment in the senior notes.

## Non-United States Holders

This section describes the tax consequences to a non-United States holder. You are a "non-United States holder" if you are the beneficial owner of a senior note (other than a partnership, including an entity treated as a partnership for United States federal income tax purposes) and are not a United States holder for United States federal income tax purposes.

### *Payment of Interest*

A non-United States holder generally will not be subject to United States federal withholding tax with respect to payments of principal and interest on the senior notes, provided that (i) the non-United States holder does not actually or constructively own 10 percent or more of the total combined voting power of all classes of our stock entitled to vote, (ii) the non-United States holder is not for United States federal income tax purposes a controlled foreign corporation related to us (directly or indirectly) through stock ownership, and (iii) the beneficial owner of the senior notes certifies to us or the fiscal and paying agent (on Internal Revenue Service Form W-8BEN, Form W-8BEN-E or other applicable form) under penalties of perjury as to its status as a non-United States holder and complies with applicable identification procedures. Special rules apply to partnerships, estates and trusts and, in certain circumstances, certifications as to foreign status and other matters may be required to be provided by partners and beneficiaries thereof.

### *Sale, Exchange or Retirement of Senior Notes*

A non-United States holder of a senior note generally will not be subject to United States federal income tax on any gain realized upon the sale, exchange, retirement or other disposition of a senior note, unless the non-United States holder is an individual who is present in the United States for 183 days or more during the taxable year of sale, retirement or other disposition and certain other conditions are met. In such case, the non-United States holder generally will be subject to a 30 percent tax on any capital gain recognized on the disposition of the senior notes, after being offset by certain United States source capital losses.

### *United States Trade or Business*

If a non-United States holder of a senior note is engaged in a trade or business in the United States and income or gain from the senior note is effectively connected with the conduct of such trade or business, the non-United States holder will be exempt from withholding tax if appropriate certification has been provided, but will generally be subject to regular United States federal income tax on such income and gain in the same manner as if it were a United States holder. In addition, if such non-United States holder is a foreign corporation, it may be subject to a branch profits tax equal to 30 percent (or lower applicable treaty rate) of its effectively connected earnings and profits for the taxable year, subject to adjustments.

***Foreign Account Tax Compliance Act***

Sections 1471 through 1474 of the United States Internal Revenue Code, the Foreign Account Tax Compliance Act or FATCA provisions, impose a 30% United States withholding tax on certain types of payments made to certain foreign entities. Failure to comply with the additional certification, information reporting and other specified requirements imposed under FATCA could result in United States withholding tax being imposed on payments of interest and principal under the senior notes and sales proceeds of the senior notes held by or through a foreign entity. United States Treasury Regulations and applicable guidance provide that FATCA withholding generally applies to payments of interest, and will apply to (i) gross proceeds from the sale, exchange or retirement of debt obligations paid after December 31, 2018, and (ii) certain pass-thru payments received with respect to debt obligations held through foreign financial institutions after the later of December 31, 2018 and the date that applicable final regulations are issued. Prospective investors should consult their own tax advisors regarding FATCA and its effect on them.

**Backup Withholding and Information Reporting**

In general, payments of interest and the proceeds of sale, exchange, retirement or other disposition of the senior notes payable by a United States paying agent or other United States intermediary will be subject to information reporting. With respect to a non-United States holder, we must report annually to the Internal Revenue Service and to each non-United States holder the amount of any interest paid to such holder regardless of whether any tax was actually withheld. Copies of the information returns reporting such interest payments to a non-United States holder and the amount of any tax withheld also may be made available to the tax authorities in the country in which the non-United States holder resides under the provisions of an applicable income tax treaty. In addition, backup withholding at the then applicable rate (currently 28 percent) will generally apply to these payments if:

- in the case of a United States holder, the holder fails to provide an accurate taxpayer identification number, fails to certify that the holder is not subject to backup withholding or fails to report all interest and dividends required to be shown on its United States federal income tax returns; or

- in the case of a non-United States holder, the holder fails to provide the certification on Internal Revenue Service Form W-8BEN, Form W-8BEN-E or other applicable form or otherwise does not provide evidence of exempt status.

Certain United States holders (including, among others, corporations) are not subject to information reporting or backup withholding. Any amount paid as backup withholding will be creditable against the holder's United States federal income tax liability and may entitle the holder to a refund, provided that the required information is timely furnished to the Internal Revenue Service. Holders of the senior notes should consult their tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining such an exemption.

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## UNDERWRITING

Subject to the terms and conditions set forth in an underwriting agreement between us and the underwriters named below, for whom Barclays Capital Inc., BNP Paribas Securities Corp., Morgan Stanley & Co. LLC, Mitsubishi UFJ Securities (USA), Inc. and The Williams Capital Group, L.P. are acting as representatives, we have agreed to sell to each of the underwriters, and each of the underwriters has severally and not jointly agreed to purchase from us, the principal amount of senior notes set forth opposite its name below.

| Underwriter | Principal Amount of Senior Notes |
|---|---|
| Barclays Capital Inc. | $ 120,000,000 |
| BNP Paribas Securities Corp. | 120,000,000 |
| Morgan Stanley & Co. LLC | 120,000,000 |
| Mitsubishi UFJ Securities (USA), Inc. | 72,000,000 |
| The Williams Capital Group, L.P. | 72,000,000 |
| BNY Mellon Capital Markets, LLC | 36,000,000 |
| TD Securities (USA) LLC | 36,000,000 |
| C.L. King & Associates, Inc. | 12,000,000 |
| Great Pacific Securities | 12,000,000 |
| Total | $ 600,000,000 |

The underwriters have agreed, subject to the terms and conditions set forth in the underwriting agreement, to purchase all of the senior notes if any of the senior notes are purchased.

The underwriters propose to offer the senior notes directly to the public at the public offering price specified on the cover page to this prospectus supplement and may also offer the senior notes to certain dealers at the public offering price less a concession not to exceed 0.40% of the principal amount of the senior notes. The underwriters may allow, and these dealers may reallow, concession to certain brokers and dealers not to exceed 0.20% of the principal amount of the senior notes. After the initial offering of the senior notes, the underwriters may change the offering price and concession.

The senior notes have no established trading market. We currently have no intention to apply to list the senior notes on any securities exchange or automated dealer quotation system. The underwriters may make a market in the senior notes after completion of the offering, but will not be obligated to make a market in the senior notes and may discontinue such market making at any time without notice. No assurance can be given as to the liquidity of the trading market for the senior notes or that an active public market for the senior notes will develop. If an active public trading market for the senior notes does not develop, the market price and liquidity of the senior notes may be adversely affected.

We will agree to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or to contribute to payments which the underwriters may be required to make in respect thereof.

We estimate our expenses for this offering, other than the underwriting discounts and commissions, to be approximately $1,300,000.

We will agree with the underwriters not to, during the period five business days from the date of the underwriting agreement, sell, offer to sell, grant any option for the sale of, or otherwise dispose of any debt securities other than the senior notes, without the prior written consent of each of Barclays Capital Inc., BNP Paribas Securities Corp., Morgan Stanley & Co. LLC, Mitsubishi UFJ Securities (USA), Inc. and The Williams Capital Group, L.P. This agreement will not apply to issuances of commercial paper or other debt securities with

scheduled maturities of less than one year and the sale or remarketing of tax-exempt bonds issued by a governmental authority or body for our benefit.

Since trades in the secondary market generally settle in three business days, purchasers who wish to trade the senior notes on the date of pricing will be required, by virtue of the fact that the senior notes initially will settle in T+5, to specify alternative settlement arrangements to prevent a failed settlement.

In order to facilitate the offering, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the senior notes. Specifically, the underwriters may over-allot in connection with the offering, creating short positions in the senior notes for their own accounts. In addition, to cover over-allotments or to stabilize the price of the senior notes, the underwriters may bid for, and purchase, senior notes in the open market. The underwriters may reclaim selling concessions allowed to an underwriter or dealer for distributing senior notes in the offering if the underwriters repurchase previously distributed senior notes in transactions to cover short positions, in stabilization transactions or otherwise. Any of these activities may stabilize or maintain the market price of the senior notes above independent market levels. The underwriters are not required to engage in these activities, and may end any of these activities at any time without notice.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased notes sold by or for the account of such underwriter in stabilizing or short covering transactions.

In general, purchases of a security for the purpose of stabilization or to reduce a short position could cause the price of the security to be higher than it might be in the absence of such purchases. The imposition of a penalty bid might also have an effect on the price of a security to the extent that it were to discourage resales of the security.

Neither we nor any underwriter makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the senior notes. In addition, neither we nor any underwriter makes any representation that the underwriters will engage in such transactions or that such transactions once commenced will not be discontinued without notice.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their affiliates have engaged and may in the future engage in transactions with, and, from time to time, have performed and may perform investment banking, corporate trust and/or commercial banking services for, us and certain of our affiliates in the ordinary course of business, for which they have received and will receive customary compensation. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments including serving as counterparties to certain derivative and hedging arrangements and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. Certain of the underwriters or their respective affiliates that have a lending relationship with us routinely hedge, and certain other of those underwriters or their respective affiliates may hedge, their credit exposure to us consistent with their customary risk management policies. Typically, these underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the notes offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the notes offered hereby. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments. Barclays Capital Inc. and The Williams Capital Group, L.P. are dealers under our commercial paper program and other underwriters or their affiliates may hold our commercial paper and may receive a portion of the net proceeds from this offering. Additionally, affiliates

of one or more of the underwriters are part of a consortium of banks that participates in our revolving credit facility or Corp's revolving credit facility and may also hold our debt securities.

**Selling Restrictions**

***Notice to Prospective Investors in the European Economic Area***

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), each underwriter has represented and agreed that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date) it has not made and will not make an offer of senior notes which are the subject of the offering contemplated by this prospectus supplement to the public in that Relevant Member State other than:

(a) to any legal entity which is a qualified investor as defined in the Prospectus Directive;

(b) to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the issuer for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of senior notes shall require the issuer or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive or supplement a prospectus pursuant to Article 16 of the Prospectus Directive.

This prospectus supplement has been prepared on the basis that any offer of senior notes in any Relevant Member State will be made pursuant to an exemption under the Prospectus Directive from the requirement to publish a prospectus for offers of the senior notes. Accordingly any person making or intending to make an offer in that Relevant Member State of senior notes which are the subject of the offering contemplated in this prospectus supplement may only do so in circumstances in which no obligation arises for the Company or any of the underwriters to publish a prospectus pursuant to Article 3 of the Prospectus Directive in relation to such offer. Neither the Company nor the underwriters have authorized, nor do they authorize, the making of any offer of senior notes in circumstances in which an obligation arises for the Company or the underwriters to publish a prospectus for such offer.

For the purposes of this provision, the expression an "offer of senior notes to the public" in relation to any senior notes in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the senior notes to be offered so as to enable an investor to decide to purchase or subscribe the senior notes, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State, the expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in the Relevant Member State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

***Notice to Prospective Investors in the United Kingdom***

This communication is only being distributed to and is only directed at (i) persons who are outside the United Kingdom or (ii) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (iii) high net worth companies, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as "relevant persons"). The senior notes are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such senior notes will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this prospectus supplement and the accompanying prospectus or any of their contents.

Each underwriter has represented, warranted and agreed that:

1.1 it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000 (the "FSMA")) received by it in connection with the issue or sale of the senior notes in circumstances in which Section 21(1) of the FSMA would not, if the issuer was not an authorised person apply to the issuer; and

1.2 it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the senior notes in, from or otherwise involving the United Kingdom.

### *Notice to Residents of Canada*

The senior notes may be sold only to purchasers in the provinces of Alberta, British Columbia, New Brunswick, Nova Scotia, Ontario, Prince Edward Island and Quebec purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the senior notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus supplement (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

### *Notice to Prospective Investors in Hong Kong*

The senior notes may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the senior notes may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to senior notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

### *Notice to Prospective Investors in Singapore*

This prospectus supplement has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus supplement and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the senior notes may not be circulated or distributed, nor may the senior notes be offered or sold, or be made the subject of an invitation for subscription or purchase,

whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the senior notes are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the senior notes under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

***Notice to Prospective Investors in Japan***

The senior notes have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any senior notes, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

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## GENERAL INFORMATION

The notes have been accepted for clearance through DTC and have been assigned the following identification number:

| | CUSIP Number | ISIN |
|---|---|---|
| Senior notes | 694308HP5 | US694308HP52 |

## LEGAL MATTERS

The validity of the senior notes will be passed upon for us by Orrick, Herrington & Sutcliffe LLP, San Francisco, California. Skadden, Arps, Slate, Meagher & Flom LLP, New York, New York represents the underwriters. Skadden, Arps, Slate, Meagher & Flom LLP has in the past performed, and continues to perform, legal services in connection with federal regulatory and transactional matters for us and our affiliates.

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**PROSPECTUS**

# Pacific Gas and Electric Company

## Senior Notes

We may offer and sell from time to time an indeterminate principal amount of senior notes in one or more offerings. This prospectus provides you with a general description of the senior notes that may be offered.

Each time we sell senior notes, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior notes. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should carefully read this prospectus and any applicable prospectus supplement for the specific offering before you invest in any of the senior notes. This prospectus may not be used to sell senior notes unless accompanied by a prospectus supplement.

The senior notes may be sold to or through underwriters, dealers or agents or directly to other purchasers. A prospectus supplement will set forth the names of any underwriters, dealers or agents involved in the sale of the senior notes, the aggregate principal amount of senior notes to be purchased by them and the compensation they will receive.

**See "Risk Factors" on page 1 for information on certain risks related to the purchase of our securities.**

**None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.**

February 11, 2014

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## ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or the SEC, using a shelf registration process. Under this shelf registration process, we may from time to time sell an indeterminate principal amount of senior notes in one or more offerings.

This prospectus provides you with only a general description of the senior notes that we may offer. This prospectus does not contain all of the information set forth in the registration statement of which this prospectus is a part, as permitted by the rules and regulations of the SEC. For additional information regarding us and the offered senior notes, please refer to the registration statement of which this prospectus is a part. Each time we sell senior notes, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior notes. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should rely only on the information in the applicable prospectus supplement if this prospectus and the applicable prospectus supplement are inconsistent. Before purchasing any senior notes, you should carefully read both this prospectus and the applicable prospectus supplement, together with the additional information described under the section of this prospectus titled "Where You Can Find More Information." In particular, you should carefully consider the risks and uncertainties described under the section titled "Risk Factors" or otherwise included in any applicable prospectus supplement or incorporated by reference in this prospectus before you decide whether to purchase the senior notes. These risks and uncertainties, together with those not known to us or those that we may deem immaterial, could impair our business and ultimately affect our ability to make payments on the senior notes.

You should rely only on the information contained or incorporated by reference in this prospectus and in any applicable prospectus supplement. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. Neither we nor any underwriter, dealer or agent will make an offer to sell the senior notes in any jurisdiction where the offer or sale is not permitted. You should assume that the information in this prospectus and any applicable prospectus supplement is accurate only as of the dates on their covers. Our business, financial condition, results of operations and prospects may have changed since those dates.

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## PACIFIC GAS AND ELECTRIC COMPANY

We are a public utility serving more than 15 million people throughout 70,000 square miles in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers.

We were incorporated in California in 1905. Our principal executive offices are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and our telephone number at that location is (415) 973-7000.

Unless otherwise indicated, when used in this prospectus, the terms "we," "our," "ours" and "us" refer to Pacific Gas and Electric Company and its subsidiaries, and the term "Corp" refers to our parent, PG&E Corporation.

## RISK FACTORS

Investing in our securities involves risk. Please see risk factors described in our Annual Report on Form 10-K and other reports filed with the SEC, which are all incorporated by reference in this prospectus. Before making an investment decision, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus or the applicable supplement to this prospectus. The risks and uncertainties described are not the only ones facing us. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations, financial results and the value of our securities.

## FORWARD-LOOKING STATEMENTS

This prospectus, the documents incorporated by reference in this prospectus and any applicable prospectus supplement contain forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts as of the date of this prospectus. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations; forecasts of costs we will incur to make safety and reliability improvements, including natural gas transmission costs that we will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those related to environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- when and how the pending California Public Utilities Commission ("CPUC") investigations and enforcement matters related to our natural gas system operating practices and our natural gas transmission pipeline rupture and fire that occurred on September 9, 2010 in San Bruno, California (the "San Bruno accident") are concluded, including the ultimate amount of fines we will be required to pay to the State General Fund, the amount of natural gas transmission costs we will be prohibited from recovering, and the cost of any remedial actions we may be ordered to perform;
- the outcome of the pending federal criminal investigation related to the San Bruno accident, including the ultimate amount of civil or criminal fines or penalties, if any, we may be required to pay, and the impact of remedial measures we are required to take such as the appointment of an independent monitor;

- whether we are able to repair the reputational harm that we have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident and the decisions to be issued in the pending investigations, including any charge or finding of criminal liability;

- the outcomes of our ratemaking proceedings, such as the 2014 general rate case, the 2015 gas transmission and storage rate case, and the transmission owner rate cases;

- the amount and timing of additional common stock issuances by Corp, the proceeds of which are contributed as equity to maintain our authorized capital structure as we incur charges and costs that we cannot recover through rates, including costs and fines associated with natural gas matters and the pending investigations;

- the outcome of future regulatory investigations, citations, or other proceedings, that may be commenced relating to our compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of our electric and gas facilities;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge our known and unknown remediation obligations; the extent to which we are able to recover environmental compliance and remediation costs in rates or from other sources; and the ultimate amount of environmental remediation costs we incur but do not recover, such as the remediation costs associated with our natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or Nuclear Regulatory Commission ("NRC") regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; and whether we decide to request that the NRC resume processing our renewal application for the two Diablo Canyon nuclear power plant operating licenses, and if so, whether the NRC grants the renewal;

- the impact of weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt our service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by us, our customers, or third parties on which we rely; and subject us to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on us;

- the impact of environmental laws and regulations aimed at the reduction of carbon dioxide and greenhouse gases, and whether we are able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline in our service area, general and regional economic and financial market conditions, the extent of municipalization of our electric or gas distribution facilities, changing levels of "direct access" customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators," and the development of alternative energy technologies including self-generation, storage and distributed generation technologies;

- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; the extent to which we can manage and respond to the volatility of energy commodity prices; the ability of us and our counterparties to post or return collateral in connection with price risk management activities; and whether we are able to recover timely our energy commodity costs through rates;

- whether our information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether we are able to protect our operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether our security measures are sufficient to protect confidential customer, vendor, and financial data contained in such systems and networks; and whether we can continue to rely on third-party vendors and contractors that maintain and support some of our operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- Corp's and our ability to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if we were to lose our investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, or regulations; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the more significant risks that could affect the outcome of these forward-looking statements and our future financial condition and results of operations, you should read the sections of the documents incorporated herein by reference titled "Risk Factors" as well as the important factors set forth under the heading "Risk Factors" in the applicable supplement to this prospectus.

You should read this prospectus, any applicable prospectus supplements, the documents that we incorporate by reference into this prospectus, the documents that we have included as exhibits to the registration statement of which this prospectus is a part and the documents that we refer to under the section of this prospectus titled "Where You Can Find More Information" completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statement. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus, the date of the document incorporated by reference or the date of any applicable prospectus supplement. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our historical ratios of earnings to fixed charges for the periods indicated:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | 2010 | 2009 |
| Ratio of earnings to fixed charges | 2.23x | 2.24x | 2.51x | 3.12x | 3.12x |

For the purpose of computing the ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases and allowance for funds used during construction related to the cost of debt and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

## USE OF PROCEEDS

Each prospectus supplement will describe the uses of the proceeds from the issuance of the senior notes offered by that prospectus supplement.

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## DESCRIPTION OF THE SENIOR NOTES

This prospectus describes certain general terms of the senior notes that we may sell from time to time under this prospectus. We will describe the specific terms of each series of senior notes we offer in a prospectus supplement. The senior notes will be issued under an indenture dated as of April 22, 2005 (which supplemented, amended and restated the original indenture dated as of March 11, 2004 as thereafter supplemented) and one or more supplemental indentures that we will enter into with The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A. and successor to BNY Western Trust Company), as trustee. We have summarized selected provisions of the indenture and the senior notes below. The information we are providing you in this prospectus concerning the senior notes and the indenture is only a summary of the information provided in those documents, and the summary is qualified in its entirety by reference to the provisions of the indenture, including the forms of senior notes attached thereto. You should consult the senior notes themselves and the indenture for more complete information on the senior notes as they, and not this prospectus or any prospectus supplement, govern your rights as a holder. The indenture is included as an exhibit to the registration statement of which this prospectus is a part. The indenture has been qualified under the Trust Indenture Act of 1939, as amended, or the Trust Indenture Act, and the terms of the senior notes will include those made part of the indenture by the Trust Indenture Act.

In this section, references to "we,&4148; "our," "ours" and "us" refer only to Pacific Gas and Electric Company and not to any of its direct or indirect subsidiaries or affiliates except as expressly provided.

### General

The senior notes are our unsecured general obligations and will rank equally in right of payment to all our other senior and unsubordinated debt. The senior notes will be entitled to the benefit of the indenture equally and ratably with all other senior notes issued under the indenture.

The indenture does not limit the amount of debt we may issue under it or the amount of debt we or our subsidiaries may otherwise incur. We may issue senior notes from time to time under the indenture in one or more series by entering into supplemental indentures or by resolution of our board of directors.

### Provisions of a Particular Series

The prospectus supplement applicable to each series of senior notes will specify, among other things:

- the title of the senior notes;
- any limit on the aggregate principal amount of the senior notes;
- the date or dates on which the principal of the senior notes is payable, including the maturity date, or the method or means by which those dates will be determined, and our right, if any, to extend those dates and the duration of any extension;
- the interest rate or rates of the senior notes, if any, which may be fixed or variable, or the method or means by which the interest rate or rates will be determined, and our ability to extend any interest payment periods and the duration of any extension;
- the date or dates from which any interest will accrue, the dates on which we will pay interest on the senior notes and the regular record date, if any, for determining who is entitled to the interest payable on any interest payment date;
- any periods or periods within which, or date or dates on which, the price or prices at which and the terms and conditions on which the senior notes may be redeemed, in whole or in part, at our option;

- any obligation of ours to redeem, purchase or repay the senior notes pursuant to any sinking fund or other mandatory redemption provisions or at the option of the holder and the terms and conditions upon which the senior notes will be so redeemed, purchased or repaid;
- the denominations in which we will authorize the senior notes to be issued, if other than $1,000 or integral multiples of $1,000;
- whether we will offer the senior notes in the form of global securities and, if so, the name of the depositary for any global securities;
- if the amount payable in respect of principal of or any premium or interest on any senior notes may be determined with reference to an index or other fact or event ascertainable outside the indenture, the manner in which such amount will be determined;
- covenants for the benefit of the holders of that series;
- the currency or currencies in which the principal, premium, if any, and interest on the senior notes will be payable if other than U.S. dollars and the method for determining the equivalent amount in U.S. dollars;
- if the principal of the senior notes is payable from time to time without presentation or surrender, any method or manner of calculating the principal amount that is outstanding at any time for purposes of the indenture; and
- any other terms of the senior notes.

We may sell senior notes at par or at a discount below their stated principal amount. We will describe in a prospectus supplement material U.S. federal income tax considerations, if any, and any other special considerations for any senior notes we sell that are denominated in a currency other than U.S. dollars.

**Payment**

Except as may be provided with respect to a series, interest, if any, on the senior notes payable on each interest payment date will be paid to the person in whose name that senior note is registered as of the close of business on the regular record date for the interest payment date. However, interest payable at maturity will be paid to the person to whom the principal is paid. If there has been a default in the payment of interest on any senior notes, the defaulted interest may be paid to the holders of the senior notes as of a date between 10 and 30 days before the date we propose for payment of defaulted interest or in any other manner not inconsistent with the requirements of any securities exchange on which those senior notes may be listed, if the trustee finds it practicable.

**Redemption**

Any terms for the optional or mandatory redemption of a series of senior notes will be set forth in a prospectus supplement for the offered series. Unless otherwise indicated in a prospectus supplement, senior notes will be redeemable by us only upon notice by mail not less than 30 nor more than 60 days before the date fixed for redemption and, if less than all the senior notes of a series are to be redeemed, the particular senior notes to be redeemed will be selected by the method provided for that particular series, or in the absence of any such provision, by such method of random selection as the registrar deems fair and appropriate.

We have reserved the right to provide conditional redemption notices for redemptions at our option or for redemptions that are contingent upon the occurrence or nonoccurrence of an event or condition that cannot be ascertained prior to the time we are required to notify holders of the redemption. A conditional notice may state that if we have not deposited redemption funds with the trustee or a paying agent on or before the redemption date or we have directed the trustee or paying agent not to apply money deposited with it for redemption of senior notes, we will not be required to redeem the senior notes on the redemption date.

**Restrictions on Liens and Sale and Leaseback Transactions**

The indenture does not permit us or any of our significant subsidiaries (as defined below) to, (i) issue, incur, assume or permit to exist any debt (as defined below) secured by a lien (as defined below) on any of our principal property (as defined below) or any of our significant subsidiaries' principal property, whether that principal property was owned when the original indenture was executed (March 11, 2004) or thereafter acquired, unless we provide that the senior notes will be equally and ratably secured with the secured debt or (ii) incur or permit to exist any attributable debt (as defined below) in respect of principal property; provided, however, that the foregoing restriction will not apply to the following:

- to the extent we or a significant subsidiary consolidates with, or merges with or into, another entity, liens on the property of the entity securing debt in existence on the date of the consolidation or merger, provided that the debt and liens were not created or incurred in anticipation of the consolidation or merger and that the liens do not extend to or cover any of our or a significant subsidiary's principal property;

- liens on property acquired after March 11, 2004 and existing at the time of acquisition, as long as the lien was not created or incurred in anticipation thereof and does not extend to or cover any other principal property;

- liens of any kind, including purchase money liens, conditional sales agreements or title retention agreements and similar agreements, upon any property acquired, constructed, developed or improved by us or a significant subsidiary (whether alone or in association with others) which do not exceed the cost or value of the property acquired, constructed, developed or improved and which are created prior to, at the time of, or within 12 months after the acquisition (or in the case of property constructed, developed or improved, within 12 months after the completion of the construction, development or improvement and commencement of full commercial operation of the property, whichever is later) to secure or provide for the payment of any part of the purchase price or cost thereof; provided that the liens do not extend to any principal property other than the property so acquired, constructed, developed or improved;

- liens in favor of the United States, any state or any foreign country or any department, agency or instrumentality or any political subdivision of the foregoing to secure payments pursuant to any contract or statute or to secure any indebtedness incurred for the purpose of financing all or any part of the purchase price or cost of constructing or improving the property subject to the lien, including liens related to governmental obligations the interest on which is tax-exempt under Section 103 of the Internal Revenue Code of 1986, as amended, or the Code, or any successor section of the Code;

- liens in favor of us, one or more of our significant subsidiaries, one or more of our wholly owned subsidiaries or any of the foregoing combination; and

- replacements, extensions or renewals (or successive replacements, extensions or renewals), in whole or in part, of any lien or of any agreement referred to in the bullet points above or replacements, extensions or renewals of the debt secured thereby (to the extent that the amount of the debt secured by the lien is not increased from the amount originally so secured, plus any premium, interest, fee or expenses payable in connection with any replacements, refundings, refinancings, remarketings, extensions or renewals); provided that replacement, extension or renewal is limited to all or a part of the same property (plus improvements thereon or additions or accessions thereto) that secured the lien replaced, extended or renewed.

Notwithstanding the restriction described above, we or any significant subsidiary may, (i) issue, incur or assume debt secured by a lien not described in the immediately preceding six bullet points on any principal property owned at March 11, 2004 or thereafter acquired without providing that the outstanding senior notes be equally and ratably secured with that debt and (ii) issue or permit to exist attributable debt in respect of principal property, in either case, so long as the aggregate amount of that secured debt and attributable debt, together with

the aggregate amount of all other debt secured by liens on principal property not described in the immediately preceding six bullet points then outstanding and all other attributable debt in respect of principal property, does not exceed 10% of our net tangible assets, as determined by us as of a month end not more than 90 days prior to the closing or consummation of the proposed transaction.

For these purposes:

- "attributable debt" in respect of a sale and leaseback transaction means, at the time of determination, the present value of the obligation of the lessee for net rental payments during the remaining term of the lease included in the sale and leaseback transaction, including any period for which the lease has been extended or may, at the option of the lessor, be extended. The present value shall be calculated using a discount rate equal to the rate of interest implicit in the transaction, determined in accordance with generally accepted accounting principals, or GAAP.

- "capital lease obligation" means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet in accordance with GAAP.

- "debt" means any debt of ours for money borrowed and guarantees by us of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- "debt" of a significant subsidiary means any debt of such significant subsidiary for money borrowed and guarantees by the significant subsidiary of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- "excepted property" means any right, title or interest of us or any of our significant subsidiaries in, to or under any of the following property, whether owned at March 11, 2004 or thereafter acquired:

  - all money, investment property and deposit accounts (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), and all cash on hand or on deposit in banks or other financial institutions, shares of stock, interests in general or limited partnerships or limited liability companies, bonds, notes, other evidences of indebtedness and other securities, of whatever kind and nature;

  - all accounts, chattel paper, commercial tort claims, documents, general intangibles, instruments, letter-of-credit rights and letters of credit (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), with certain exclusions such as licenses and permits to use the real property of others, and all contracts, leases (other than the lease of certain real property at our Diablo Canyon power plant), operating agreements and other agreements of whatever kind and nature; and all contract rights, bills and notes;

  - all revenues, income and earnings, all accounts receivable, rights to payment and unbilled revenues, and all rents, tolls, issues, product and profits, claims, credits, demands and judgments, including any rights in or to rates, revenue components, charges, tariffs, or amounts arising therefrom, or in any amounts that are accrued and recorded in a regulatory account for collection by us or any significant subsidiary;

  - all governmental and other licenses, permits, franchises, consents and allowances including all emission allowances (or similar rights) created under any similar existing or future law relating to abatement or control of pollution of the atmosphere, water or soil, other than all licenses and permits to use the real property of others, franchises to use public roads, streets and other public properties, rights of way and other rights, or interests relating to the occupancy or use of real property;

  - all patents, patent licenses and other patent rights, patent applications, trade names, trademarks, copyrights and other intellectual property, including computer software and software licenses;

- all claims, credits, choses in action, and other intangible property;
- all automobiles, buses, trucks, truck cranes, tractors, trailers, motor vehicles and similar vehicles and movable equipment; all rolling stock, rail cars and other railroad equipment; all vessels, boats, barges and other marine equipment; all airplanes, helicopters, aircraft engines and other flight equipment; and all parts, accessories and supplies used in connection with any of the foregoing;
- all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; all materials, supplies, inventory and other items of personal property that are consumable (otherwise than by ordinary wear and tear) in their use in the operation of the principal property; all fuel, whether or not that fuel is in a form consumable in the operation of the principal property, including separate components of any fuel in the forms in which those components exist at any time before, during or after the period of the use thereof as fuel; all hand and other portable tools and equipment; and all furniture and furnishings;
- all personal property the perfection of a security interest in which is not governed by the California Commercial Code;
- all oil, gas and other minerals (as those terms are defined in the California Commercial Code as in effect on March 11, 2004) and all coal, ore, gas, oil and other minerals and all timber, and all rights and interests in any of the foregoing, whether or not the minerals or timber have been mined or extracted or otherwise separated from the land; and all electric energy and capacity, gas (natural or artificial), steam, water and other products generated, produced, manufactured, purchased or otherwise acquired by us or any significant subsidiary;
- all property which is the subject of a lease agreement other than a lease agreement that results from a sale and leaseback transaction designating us or any significant subsidiary as lessee and all our, or a significant subsidiary's right, title and interest in and to that property and in, to and under that lease agreement, whether or not that lease agreement is intended as security (other than certain real property leased at our Diablo Canyon power plant and the related lease agreement);
- real, personal and mixed properties of an acquiring or acquired entity unless otherwise made a part of principal property; and
- all proceeds (as that term is defined in the California Commercial Code as in effect on March 11, 2004) of the property listed in the preceding bullet points;

- "lien" means any mortgage, deed of trust, pledge, security interest, encumbrance, easement, lease, reservation, restriction, servitude, charge or similar right and any other lien of any kind, including, without limitation, any conditional sale or other title retention agreement, any lease of a similar nature, and any defect, irregularity, exception or limitation in record title or, when the context so requires, any lien, claim or interest arising from anything described in this bullet point.
- "net tangible assets" means the total amount of our assets determined on a consolidated basis in accordance with GAAP, less (i) the sum of our consolidated current liabilities determined in accordance with GAAP and (ii) the amount of our consolidated assets classified as intangible assets determined in accordance with GAAP, including, but not limited to, such items as goodwill, trademarks, trade names, patents, and unamortized debt discount and expense and regulatory assets carried as an asset on our consolidated balance sheet.
- "principal property" means any property of ours or any of our significant subsidiaries, as applicable, other than excepted property.
- "significant subsidiary" has the meaning specified in Rule 1-02(w) of Regulation S-X under the Securities Act of 1933, as amended, or the Securities Act; provided that, significant subsidiary shall not include any corporation or other entity substantially all the assets of which are excepted property.

- "swap agreement" means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions.

**Consolidation, Merger, Conveyance or Other Transfer**

We may not consolidate with or merge with or into any other person (as defined below) or convey, otherwise transfer or lease all or substantially all of our principal property to any person unless:

- the person formed by that consolidation or into which we are merged or the person which acquires by conveyance or other transfer, or which leases, all or substantially all of the principal property is a corporation, partnership, limited liability company, association, company, joint stock company or business trust, organized and existing under the laws of the United States, or any state thereof or the District of Columbia;

- the person executes and delivers to the trustee a supplemental indenture that in the case of a consolidation, merger, conveyance or other transfer, or in the case of a lease if the term thereof extends beyond the last stated maturity of the senior notes then outstanding, contains an assumption by the successor person of the due and punctual payment of the principal of and premium, if any, and interest, if any, on all senior notes then outstanding and the performance and observance of every covenant and condition under the indenture to be performed or observed by us;

- in the case of a lease, the lease is made expressly subject to termination by us or by the trustee at any time during the continuance of an event of default under the indenture;

- immediately after giving effect to the transaction and treating any indebtedness that becomes our obligation as a result of the transaction as having been incurred by us at the time of the transaction, no default or event of default under the indenture shall have occurred and be continuing; and

- we have delivered to the trustee an officer's certificate and an opinion of counsel, each stating that the merger, consolidation, conveyance, lease or transfer, as the case may be, fully complies with all provisions of the indenture; provided, however, that the delivery of the officer's certificate and opinion of counsel shall not be required with respect to any merger, consolidation, conveyance, lease or transfer between us and any of our wholly owned subsidiaries.

Notwithstanding the foregoing, we may merge or consolidate with or transfer all or substantially all of our assets to an affiliate that has no significant assets or liabilities and was formed solely for the purpose of changing our jurisdiction of organization or our form of organization or for the purpose of forming a holding company; provided that the amount of our indebtedness is not increased; and provided, further that the successor assumes all of our obligations under the indenture.

In the case of the conveyance or other transfer of all or substantially all of our principal property to any person as contemplated under the indenture, upon the satisfaction of all the conditions described above, we (as we would exist without giving effect to the transaction) would be released and discharged from all obligations and covenants under the indenture and under the senior notes then outstanding unless we elect to waive the release and discharge.

The meaning of the term "substantially all" has not been definitely established and is likely to be interpreted by reference to applicable state law if and at the time the issue arises and will depend on the facts and circumstances existing at the time.

For these purposes, "person" means any individual, corporation, partnership, limited liability company, association, company, joint stock company, limited liability partnership, joint venture, trust or unincorporated organization, or any other entity whether or not a legal entity, or any governmental authority.

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**Additional Covenants**

We have agreed in the indenture, among other things:

- to maintain a place of payment;
- to maintain our corporate existence (subject to the provisions above relating to mergers and consolidations); and
- to deliver to the trustee an annual officer's certificate with respect to our compliance with our obligations under the indenture.

**Modification of the Indenture; Waiver**

We and the trustee may, with the consent of the holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the indenture, considered as one class, modify or amend the indenture, including the provisions relating to the rights of the holders of senior notes of the affected series. However, no modification or amendment may, without the consent of each holder of affected senior notes:

- change the stated maturity (except as provided by the terms of a series of senior notes) of the principal of, or interest on, the senior note or reduce the principal amount or any premium payable on the senior note or reduce the interest rate of the senior note, or change the method of calculating the interest rate with respect to the senior note;
- reduce the amount of principal of any discount senior note that would be payable upon acceleration of the maturity of the senior note;
- change the coin, currency or other property in which the senior note or interest or premium on the senior note is payable;
- impair the right to institute suit for the enforcement of any payment on the senior note;
- reduce the percentage in principal amount of outstanding senior notes the consent of whose holders is required for modification or amendment of the indenture or for waiver of compliance with certain provisions of the indenture or for waiver of defaults;
- reduce the quorum or voting requirements applicable to holders of the senior notes; or
- modify the provisions of the indenture with respect to modification and waiver, except as provided in the indenture.

We and the trustee may, without the consent of any holder of senior notes, modify and amend the indenture for certain purposes, including to:

- add covenants or other provisions applicable to us and for the benefit of the holders of senior notes or one or more specified series thereof or to surrender any right or power conferred on us;
- cure any ambiguity or to correct or supplement any provision of the indenture which may be defective or inconsistent with other provisions;
- make any other additions to, deletions from or changes to the provisions under the indenture so long as the additions, deletions or changes do not materially adversely affect the holders of any series of senior notes in any material respect;
- change or eliminate any provision of the indenture or add any new provision so long as the change, elimination or addition does not adversely affect the interests of holders of senior notes of any series in any material respect; and

- change any place or places for payment or surrender of senior notes and where notices and demands to us may be served.

The holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the indenture, voting as a single class, may waive compliance by us with our covenant in respect of our corporate existence and the covenants described under "Restrictions on Liens and Sale and Leaseback Transactions" and "Consolidation, Merger, Conveyance or Transfer" and with certain covenants and restrictions that may apply to a series of senior notes as provided in the indenture. The holders of not less than a majority in aggregate principal amount of the senior notes outstanding may, on behalf of the holders of all of the senior notes, waive any past default under the indenture and its consequences, except a default in the payment of the principal of or any premium or interest on any senior note and defaults in respect of a covenant or provision in the indenture which cannot be modified, amended or waived without the consent of each holder of affected senior notes.

In order to determine whether the holders of the requisite principal amount of the outstanding senior notes have taken an action under the indenture as of a specified date:

- the principal amount of a discount senior note that will be deemed to be outstanding will be the amount of the principal that would be due and payable as of that date upon acceleration of the maturity to that date; and

- senior notes owned by us or any other obligor upon the senior notes or any of our or their affiliates will be disregarded and deemed not to be outstanding.

**Events of Default**

An "event of default" means any of the following events which shall occur and be continuing:

- failure to pay interest on a senior note within 30 days after the interest becomes due and payable;

- failure to pay the principal of, or sinking fund payment or premium, if any, on, a senior note when due and payable;

- failure to perform or breach of any other covenant or warranty applicable to us in the indenture continuing for 90 days after the trustee gives us, or the holders of at least 33% in aggregate principal amount of the senior notes then outstanding give us and the trustee, written notice specifying the default or breach and requiring us to remedy the default or breach, unless the trustee or the trustee and holders of a principal amount of senior notes not less than the principal amount of senior notes the holders of which gave that notice agree in writing to an extension of the period prior to its expiration;

- certain events of bankruptcy, insolvency or reorganization; and

- the occurrence of any event of default as defined in any mortgage, indenture or instrument under which there may be issued, or by which there may be secured or evidenced, any of our debt, whether the debt existed on March 23, 2004 (the date senior notes were first issued under the original indenture), or is thereafter created, if the event of default: (i) is caused by a failure to pay principal after final maturity of the debt after the expiration of the grace period provided in the debt (which we refer to as a "payment default") or (ii) results in the acceleration of the debt prior to its express maturity, and, in each case, the principal amount of the debt, together with the principal amount of any other debt under which there has been a payment default or the maturity of which has been so accelerated, aggregates $100 million or more.

The $100 million amount specified in the bullet point above shall be increased in any calendar year subsequent to 2004 by the same percentage increase in the urban CPI for the period commencing January 1, 2004

and ending on January 1 of the applicable calendar year. "Debt" for the purpose of the bullet point above means any debt of ours for money borrowed but, in each case, excluding liabilities in respect of capital lease obligations or swap agreements.

If the trustee deems it to be in the interest of the holders of the senior notes, it may withhold notice of default, except defaults in the payment of principal of or interest or premium on or with respect to, any senior note.

If an event of default occurs and is continuing, the trustee or the holders of not less than 33% in aggregate principal amount of the senior notes outstanding, considered as one class, may declare all principal due and payable immediately by notice in writing to us (and to the trustee if given by holders); provided, however, that if an event of default occurs with respect to the specified events of bankruptcy, insolvency or reorganization, then the senior notes outstanding shall be due and payable immediately without further action by the trustee or holders. If, after such a declaration of acceleration, we pay or deposit with the trustee all overdue interest and principal and premium on senior notes that would have been due otherwise, plus any interest and other conditions specified in the indenture have been satisfied before a judgment or decree for payment has been obtained by the trustee as provided in the indenture, the event or events of default giving rise to the acceleration will be deemed to have been waived and the declaration of acceleration and its consequences will be deemed to have been rescinded and annulled.

No holder of senior notes will have any right to enforce any remedy under the indenture unless the holder has given the trustee written notice of a continuing event of default, the holders of at least 33% in aggregate principal amount of the senior notes outstanding have requested the trustee in writing to institute proceedings in respect of the event of default in its own name as trustee under the indenture and the holder or holders have offered the trustee reasonable indemnity against costs, expenses and liabilities with respect to the request, the trustee has failed to institute any proceeding within 60 days after receiving the notice from holders, and no direction inconsistent with the written request has been given to the trustee during the 60-day period by holders of at least a majority in aggregate principal amount of senior notes then outstanding.

The trustee is not required to risk its funds or to incur financial liability if there is a reasonable ground for believing that repayment to it or adequate indemnity against risk or liability is not reasonably assured.

If an event of default has occurred and is continuing, holders of not less than a majority in principal amount of the senior notes then outstanding generally may direct the time, method and place of conducting any proceedings for any remedy available to the trustee, or exercising any trust or power conferred upon the trustee; provided the direction could not involve the trustee in personal liability where indemnity would not, in the trustee's sole discretion, be adequate.

**Satisfaction and Discharge**

Any senior note, or any portion of the principal amount thereof, will be deemed to have been paid for purposes of the indenture, and our entire indebtedness in respect of the senior notes will be deemed to have been satisfied and discharged, if certain conditions are satisfied, including an irrevocable deposit with the trustee or any paying agent (other than us) in trust of:

- money in an amount which will be sufficient; or
- in the case of a deposit made prior to the maturity of the senior notes or portions thereof, eligible obligations (as described below) which do not contain provisions permitting the redemption or other prepayment thereof at the option of the issuer thereof, the principal of and the interest on which when due, without any regard to reinvestment thereof, will provide monies which, together with the money, if any, deposited with or held by the trustee or the paying agent, will be sufficient; or
- a combination of either of the two items described in the two preceding bullet points which will be sufficient;

to pay when due the principal of and premium, if any, and interest, if any, due and to become due on the senior notes or portions thereof.

This discharge of the senior notes through the deposit with the trustee of cash or eligible obligations generally will be treated as a taxable disposition for U.S. federal income tax purposes by the holders of those senior notes. Prospective investors in the senior notes should consult their own tax advisors as to the particular U.S. federal income tax consequences applicable to them in the event of such discharge.

For this purpose, "eligible obligations" for U.S. dollar-denominated senior notes, means securities that are direct obligations of, or obligations unconditionally guaranteed by, the United States, entitled to the benefit of the full faith and credit thereof, or depositary receipts issued by a bank as custodian with respect to these obligations or any specific interest or principal payments due in respect thereof held by the custodian for the account of the holder of a depository receipt.

**Transfer and Exchange**

Senior notes of any series may be exchanged for other senior notes of the same series of authorized denominations and of like aggregate principal amount and tenor. Subject to the terms of the indenture and the limitations applicable to global securities, senior notes may be presented for exchange or registration of transfer at the office of the registrar without service charge (unless otherwise indicated in a prospectus supplement), upon payment of any taxes and other governmental charges imposed on registration of transfer or exchange. Such transfer or exchange will be effected upon the trustee, us or the registrar, as the case may be, being satisfied with the instruments of transfer.

If we provide for any redemption of a series of senior notes, we will not be required to execute, register the transfer of or exchange any senior note of that series for 15 days before a notice of redemption is mailed or register the transfer of or exchange any senior note selected for redemption.

**Global Securities**

Unless we indicate differently in a prospectus supplement, senior notes initially will be issued in book-entry form and represented by one or more global securities (collectively, the "global securities"), with an aggregate principal amount equal to that of the senior notes they represent. The global securities will be deposited with, or on behalf of, The Depositary Trust Company, New York, New York, as depositary ("DTC"), and registered in the name of Cede & Co., the nominee of DTC. Unless and until it is exchanged for individual certificates evidencing securities under the limited circumstances described below, a global security may not be transferred except as a whole by the depositary to its nominee or by the nominee to the depositary, or by the depositary or its nominee to a successor depositary or to a nominee of the successor depositary.

DTC has advised us that it is:

- a limited-purpose trust company organized under the New York Banking Law;
- a "banking organization" within the meaning of the New York Banking Law;
- a member of the Federal Reserve System;
- a "clearing corporation" within the meaning of the New York Uniform Commercial Code; and
- a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934.

DTC holds securities that its participants deposit with DTC. DTC also facilitates the settlement among its participants of securities transactions, including transfers and pledges, in deposited securities through electronic

computerized book-entry changes in participants' accounts, which eliminates the need for physical movement of securities certificates. "Direct participants" in DTC include securities brokers and dealers, including underwriters, banks, trust companies, clearing corporations and other organizations. DTC is a wholly owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC National Securities Clearance Corporation, all of which are registered clearing agencies, DTC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others, referred to as "indirect participants," that clear transactions through or maintain a custodial relationship with a direct participant either directly or indirectly. The rules applicable to DTC and its participants are on file with the SEC.

Purchases of securities within the DTC system must be made by or through direct participants, which will receive a credit for those securities on DTC's records. The ownership interest of the actual purchaser of a security, which we sometimes refer to as a "beneficial owner," is in turn recorded on the direct and indirect participants' records. Beneficial owners of securities will not receive written confirmation from DTC of their purchases. However, beneficial owners are expected to receive written confirmations providing details of their transactions, as well as periodic statements of their holdings, from the direct or indirect participants through which they purchased securities. Transfers of ownership interests in global securities are to be accomplished by entries made on the books of participants acting on behalf of beneficial owners. Beneficial owners will not receive certificates representing their ownership interests in the global securities except under the limited circumstances described below.

To facilitate subsequent transfers, all global securities deposited by direct participants with DTC will be registered in the name of DTC's partnership nominee, Cede & Co, or such other name as may be requested by an authorized representative of DTC. The deposit of securities with DTC and their registration in the name of Cede & Co. or such other nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual beneficial owners of the securities. DTC's records reflect only the identity of the direct participants to whose accounts the securities are credited, which may or may not be the beneficial owners. The direct and indirect participants are responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to direct participants, by direct participants to indirect participants and by direct participants and indirect participants to beneficial owners will be governed by arrangements among them, subject to any legal requirements in effect from time to time. Beneficial owners of securities may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the securities, such as redemptions, tenders, defaults, and proposed amendments to the security documents. For example, beneficial owners of securities may wish to ascertain that the nominee holding the securities for their benefit has agreed to obtain and transmit notices to beneficial owners. In the alternative, beneficial owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices will be sent to DTC or its nominee. If less than all of the securities of a particular series are being redeemed, DTC's practice is to determine by lot the amount of the interest of each direct participant in such issue to be redeemed.

In any case where a vote may be required with respect to securities of a particular series, neither DTC nor Cede & Co. (nor any other DTC nominee) will give consents for or vote the global securities, unless authorized by a direct participant in accordance with DTC's procedures. Under its usual procedures, DTC will mail an omnibus proxy to us as soon as possible after the record date. The omnibus proxy assigns the consenting or voting rights of Cede & Co. to those direct participants to whose accounts the securities of such series are credited on the record date identified in a listing attached to the omnibus proxy.

Principal and interest payments on the securities will be made to Cede & Co., as or such other nominee as may be requested by authorized representative of DTC. DTC's practice is to credit direct participants' accounts upon receipt of funds and corresponding detail information from us or the paying agent in accordance with their respective holdings shown on DTC's records. Payments by direct and indirect participants to beneficial owners will be governed by standing instructions and customary practices, as is the case with securities held for the

account of customers in bearer form or registered in "street name." Those payments will be the responsibility of participants and not of DTC, the paying agent or us, subject to any legal requirements in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may otherwise be requested by an authorized representative of DTC) is our responsibility, disbursement of payments to direct participants is the responsibility of DTC and disbursement of payments to the beneficial owners is the responsibility of direct and indirect participants.

Except under the limited circumstances described below, purchasers of securities will not be entitled to have securities registered in their names and will not receive physical delivery of securities. Accordingly, each beneficial owner must rely on the procedures of DTC and its participants to exercise any rights under the securities and the applicable indenture.

The laws of some jurisdictions may require that some purchasers of securities take physical delivery of securities in definitive form. Those laws may impair the ability to transfer or pledge beneficial interests in securities.

DTC may discontinue providing its services as securities depository with respect to the securities at any time by giving us reasonable notice. Under such circumstances, in the event that a successor securities depository is not obtained, certificates representing the securities are required to be printed and delivered. Also, we may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository), in which event, certificates representing the securities will be printed and delivered to DTC.

We have obtained the information in this section and elsewhere in this prospectus concerning DTC and DTC's book-entry system from sources that are believed to be reliable, but we take no responsibility for the accuracy of this information.

**Resignation or Removal of Trustee**

The trustee may resign at any time upon written notice to us and the trustee may be removed at any time by written notice delivered to the trustee and us and signed by the holders of at least a majority in principal amount of the outstanding senior notes. No resignation or removal of a trustee will take effect until a successor trustee accepts appointment. In addition, under certain circumstances, we may remove the trustee. We must give notice of resignation and removal of the trustee or the appointment of a successor trustee to all holders of senior notes as provided in the indenture.

**Trustees, Paying Agents and Registrars for the Senior Notes**

The Bank of New York Mellon Trust Company, N.A. acts as the trustee, paying agent and registrar under the indenture. We may change either the paying agent or registrar without prior notice to the holders of the senior notes, and we may act as paying agent. We and our affiliates maintain ordinary banking and trust relationships with a number of banks and trust companies, including The Bank of New York Mellon Trust Company, N.A.

**Governing Law**

The indenture and the senior notes are governed by California law.

## PLAN OF DISTRIBUTION

We may sell any series of senior notes being offered by this prospectus in one or more of the following ways from time to time:

- to underwriters or dealers for resale to the public or to institutional investors;
- directly to institutional investors; or
- through agents to the public or to institutional investors.

A prospectus supplement applicable to each series of senior notes will state the terms of the offering of the senior notes, including:

- the name or names of any underwriters or agents;
- the purchase price of the senior notes and the proceeds to be received by us from the sale;
- any underwriting discounts or agency fees and other items constituting underwriters' or agents' compensation;
- any initial public offering price;
- any discounts or concessions allowed or reallowed or paid to dealers; and
- any securities exchange or automated quotation system on which the senior notes may be listed.

If we use underwriters in the sale, the senior notes will be acquired by the underwriters for their own accounts and may be resold from time to time in one or more transactions, including:

- negotiated transactions;
- at a fixed public offering price or prices, which may be changed;
- at market prices prevailing at the time of sale;
- at prices based on prevailing market prices; or
- at negotiated prices.

Senior notes may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more of those firms. The specific managing underwriter or underwriters, if any, will be named in the prospectus supplement relating to the particular senior notes together with the members of the underwriting syndicate, if any. Unless otherwise set forth in a prospectus supplement, the obligations of the underwriters to purchase the particular senior notes will be subject to certain conditions precedent and the underwriters will be obligated to purchase all of the senior notes being offered if any are purchased.

We may sell senior notes directly or through agents we designate from time to time. The prospectus supplement will set forth the name of any agent involved in the offer or sale of senior notes in respect of which such prospectus supplement is delivered and any commissions payable by us to such agent. Unless otherwise indicated in a prospectus supplement, any agent will be acting on a best efforts basis for the period of its appointment.

Any underwriters, dealers or agents participating in the distribution of senior notes may be deemed to be underwriters as defined in the Securities Act, and any discounts or commissions received by them on the sale or resale of senior notes may be deemed to be underwriting discounts and commissions under the Securities Act. We may agree with the underwriters, dealers and agents to indemnify them against certain civil liabilities, including liabilities under the Securities Act or to contribute with respect to payments which the underwriters, dealers or agents may be required to make in respect of these liabilities.

Unless otherwise specified in a prospectus supplement, senior notes will not be listed on a securities exchange. Any underwriters to whom senior notes are sold by us for public offering and sale may make a market in the senior notes, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice.

To facilitate a senior notes offering, any underwriter may engage in over-allotment, short covering transactions and penalty bids or stabilizing transactions in accordance with Regulation M under the Securities Exchange Act of 1934.

- Over-allotment involves sales in excess of the offering size, which creates a short position.
- Stabilizing transactions permit bids to purchase the underlying senior notes so long as the stabilizing bids do not exceed a specified maximum.
- Short covering positions involve purchases of senior notes in the open market after the distribution is completed to cover short positions.
- Penalty bids permit the underwriters to reclaim a selling concession from a dealer when senior notes originally sold by the dealer are purchased in a covering transaction to cover short positions.

These activities may cause the price of the senior notes to be higher than it otherwise would be. If commenced, these activities may be discontinued by the underwriters at any time.

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## EXPERTS

The consolidated financial statements and the related financial statement schedules, incorporated in this prospectus by reference from the Company's Annual Report on Form 10-K, and the effectiveness of Pacific Gas and Electric Company's internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports, which are incorporated herein by reference. Such financial statements and financial statement schedules have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

## LEGAL MATTERS

The validity of the senior notes has been passed upon for us by Orrick, Herrington & Sutcliffe LLP. The validity of the senior notes will be passed upon for any agents, dealers or underwriters by their counsel named in the applicable prospectus supplement.

## WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, information statements and other information with the SEC under File No. 001-2348. These SEC filings are available to the public over the Internet at the SEC's website at http://www.sec.gov. You may also read and copy any of these SEC filings at the SEC's public reference room at 100 F Street, N.E., Washington D.C. 20549.

## CERTAIN DOCUMENTS INCORPORATED BY REFERENCE

We have "incorporated by reference" into this prospectus certain information that we file with the SEC. This means that we can disclose important business, financial and other information in this prospectus by referring you to the documents containing this information.

We incorporate by reference the documents listed below and any future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 (other than information deemed to be furnished and not filed) before the termination of the offering of the senior notes offered hereby:

- our Annual Report on Form 10-K for the year ended December 31, 2013; and
- our Current Report on Form 8-K filed with the SEC on January 2, 2014.

The incorporation by reference of the filings listed above does not extend to any such filings made by Corp and not us or to any information in any filings jointly made by Corp and us regarding Corp or its other subsidiaries, but not regarding us.

All information incorporated by reference is deemed to be part of this prospectus except to the extent that the information is updated or superseded by information filed with the SEC after the date the incorporated information was filed (including later-dated reports listed above) or by the information contained in this prospectus or the applicable prospectus supplement. Any information that we subsequently file with the SEC that is incorporated by reference, as described above, will automatically update and supersede as of the date of such filing any previous information that had been part of this prospectus or the applicable prospectus supplement, or that had been incorporated herein by reference.

You may request a copy of these filings at no cost by writing or contacting us at the following address:

The Office of the Corporate Secretary
PG&E Corporation
77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
Telephone: (415) 973-8200
Facsimile: (415) 973-8719

Pacific Gas and Electric Company®

# $600,000,000
# 2.95% Senior Notes due March 1, 2026

**PROSPECTUS SUPPLEMENT**

**February 23, 2016**

*Joint Book-Running Managers*

**Barclays**
**BNP PARIBAS**
**Morgan Stanley**
**MUFG**
**The Williams Capital Group, L.P.**

*Co-Managers*

**BNY Mellon Capital Markets, LLC**
**TD Securities**
**C.L. King & Associates**
**Great Pacific Securities**

# Exhibit 20

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**Filed Pursuant to Rule 424(b)(2)**
**Registration No. 333-193879**

# CALCULATION OF REGISTRATION FEE

| Title of each Class of Securities to be Registered | Maximum Aggregate Offering Price | Amount of Registration Fee(1) |
|---|---|---|
| Debt Securities | $650,000,000 | $75,335 |

(1) Calculated in accordance with Rule 457(r) under the Securities Act of 1933, as amended

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**PROSPECTUS SUPPLEMENT**
**(To Prospectus dated February 11, 2014)**

Pacific Gas and Electric Company®

# $650,000,000

## $250,000,000 Floating Rate Senior Notes due November 30, 2017
## $400,000,000 4.00% Senior Notes due December 1, 2046

We are offering $250,000,000 principal amount of our Floating Rate Senior Notes due November 30, 2017, which we refer to in this prospectus supplement as our "floating rate notes" and $400,000,000 principal amount of our 4.00% Senior Notes due December 1, 2046, which we refer to in this prospectus supplement as our "2046 notes." The floating rate notes and the 2046 notes are collectively referred to in this prospectus supplement as the "senior notes."

We will pay interest on our floating rate notes offered hereby quarterly on February 28, 2017, May 30, 2017, August 30, 2017 and November 30, 2017. We will pay interest on our 2046 notes offered hereby on each June 1 and December 1, commencing June 1, 2017. The senior notes will be issued in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The floating rate notes will not be redeemable prior to maturity. We may redeem the 2046 notes in whole or in part at any time at the respective redemption prices set forth in this prospectus supplement.

The senior notes will be unsecured and will rank equally with all of our other unsecured and unsubordinated indebtedness from time to time outstanding.

There is no existing public market for the senior notes. We do not intend to apply to list the senior notes on any securities exchange or any automated quotation system.

**Investing in these senior notes involves risks. See "Risk Factors" on page S-1 of this prospectus supplement.**

| | Per Floating Rate Note | Total | Per 2046 Note | Total |
|---|---|---|---|---|
| Public Offering Price[(1)] | 100.000% | $250,000,000 | 98.164% | $392,656,000 |
| Underwriting Discounts and Commissions | 0.150% | $ 375,000 | 0.875% | $ 3,500,000 |
| Proceeds to Pacific Gas and Electric Company (before expenses)[(1)] | 99.850% | $249,625,000 | 97.289% | $389,156,000 |

[(1)] Plus accrued interest, if any, from and including original issuance of the senior notes which is expected to be December 1, 2016.

**None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus supplement or the accompanying prospectus. Any representation to the contrary is a criminal offense.**

The senior notes are expected to be delivered on or about December 1, 2016 through the book-entry facilities of The Depository Trust Company for the accounts of its participants, including Clearstream Banking, *société anonyme*, and Euroclear Bank S.A./N.V.

*Joint Book-Running Managers*

**BofA Merrill Lynch** **Citigroup** **J.P. Morgan** **Mizuho Securities**

*Co-Managers*

**CIBC Capital Markets** **SMBC Nikko** **US Bancorp**
**Lebenthal & Co., LLC** **Mischler Financial Group, Inc.** **Ramirez & Co., Inc.**

November 28, 2016

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**This prospectus supplement should be read in conjunction with the accompanying prospectus. You should rely only on the information contained in this prospectus supplement, the accompanying prospectus, the information incorporated by reference into this prospectus supplement and the accompanying prospectus and any free writing prospectus prepared by us. Neither we nor any underwriter has authorized any other person to provide you with different or additional information. If anyone provides you with different or additional information, you should not rely on it. Neither we nor any underwriter is making an offer to sell the senior notes in any jurisdiction where the offer or sale is not permitted. You should assume that the information contained in or incorporated by reference in this prospectus supplement, the accompanying prospectus and any free writing prospectus prepared by us is accurate only as of the date of the document containing the information or such other date as may be specified therein.**

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Unless otherwise indicated, when used in this prospectus supplement and the accompanying prospectus, the terms “we,” “our,” “us” and “the Company” refer to Pacific Gas and Electric Company and its subsidiaries, and the term “Corp” refers to our parent, PG&E Corporation.

## RISK FACTORS

Investing in the senior notes involves risk. These risks are described under “Risk Factors” in Item 1A of our annual report on Form 10-K for the fiscal year ended December 31, 2015 and our quarterly reports on Form 10-Q for the quarters ended March 31, 2016, June 30, 2016 and September 30, 2016, each of which is incorporated by reference in this prospectus supplement and the accompanying prospectus. See “Where You Can Find More Information” in the accompanying prospectus. Before making a decision to invest in the senior notes, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus.

## FORWARD-LOOKING STATEMENTS

This prospectus supplement, the accompanying prospectus and any documents incorporated by reference into this prospectus supplement and the accompanying prospectus contain forward-looking statements. These statements are subject to various risks and uncertainties, the realization or resolution of which may be outside of management’s control. These statements reflect management’s judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management’s knowledge of facts as of the date of this prospectus supplement.

These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that we will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as “assume,” “expect,” “intend,” “forecast,” “plan,” “project,” “believe,” “estimate,” “predict,” “anticipate,” “may,” “should,” “would,” “could,” “potential” and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the final phase two California Public Utilities Commission (“CPUC”) decision in the 2015 gas transmission and storage (“GT&S”) rate case (including whether the CPUC protects against a potential tax normalization issue identified in the phase two proposed decision), the 2017 general rate case, the transmission owner rate cases, and other ratemaking and regulatory proceedings;
- the timing and outcomes of the debarment proceeding and potential remedial and other measures that may be imposed on us as a result of the debarment proceeding and the jury’s verdict in the federal criminal trial (including a potential appointment of one or more independent third-party monitor(s)), our motion for judgment of acquittal, the Safety Enforcement Division’s (“SED”) unresolved enforcement matters relating to our compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to our compliance with natural gas-related laws and regulations, including the U.S. Attorney’s Office investigation in connection with the natural gas explosion that occurred in Carmel, California on March 3, 2014 and the U.S. Attorney’s Office in San Francisco investigation in connection with matters relating to the federal criminal trial, and the ultimate amount of fines, penalties, and remedial costs that we may incur in connection with the outcomes;
- the timing and outcomes of the CPUC’s investigation of communications between us and the CPUC that may have violated the CPUC’s rules regarding ex parte communications or are otherwise alleged to be improper, and of the U.S. Attorney’s Office in San Francisco and the California Attorney General’s office investigations in connection with communications between our personnel and CPUC

officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in our ratemaking proceedings;

- the timing and outcomes the Butte fire litigation, and whether our insurance is sufficient to cover our liability resulting therefrom or whether insurance is otherwise available; and whether additional investigations and proceedings in connection with the Butte fire will be opened;
- whether we are able to repair the harm to our reputation caused by the jury's verdict in the federal criminal trial and a possible conviction of us, the state and federal investigations of natural gas incidents, matters relating to the criminal federal trial, improper communications between the CPUC and us; our ongoing work to remove encroachments from transmission pipeline rights-of-way;
- whether we can control our costs within the authorized levels of spending, our ability to achieve sustainable efficiencies in our cost structure, the extent to which we incur unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;
- the outcome of the CPUC's investigation into our safety culture, and future legislative or regulatory actions that may be taken to require us to separate our electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;
- the outcomes of the SED's investigations of potential violations identified though audits, investigations, or self-reports, including in connection with our September 2016 self-report related to atmospheric corrosion inspections;

&1149; the outcome of future investigations or other enforcement proceedings that may be commenced relating to our compliance with laws, rules, regulations, or orders applicable to our operations, including the construction, expansion or replacement of our electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security; environmental laws and regulations;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge our known and unknown remediation obligations; and the extent to which we are able to recover environmental costs in rates or from other sources;
- the ultimate amount of unrecoverable environmental costs we incur associated with our natural gas compressor station site located near Hinkley, California;
- the impact of new legislation or Nuclear Regulatory Commission ("NRC") regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect our ability to continue operating Diablo Canyon; whether the CPUC approves the joint proposal that will phase out our Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether we obtain the approvals required to withdraw our NRC application to renew the two Diablo Canyon operating licenses; whether the State Lands Commission could be required to perform an environmental review of the new lands lease as a result of the World Business Academy's assertion that the State Lands Commission committed legal error when it determined that the short-term lease extension for an existing facility was exempt from the California Environmental Quality Act; and whether we will be able to successfully implement our retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;
- whether we are successful in ensuring physical security of our critical assets and whether our information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether we and our third party vendors and

contractors (who host, maintain, modify and update some of our systems) are able to protect our operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether our security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether we can continue to rely on third-party vendors and contractors that maintain and support some of our information technology and operating systems;

- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt our service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by us, our customers, or third parties on which we rely; whether we incur liability to third parties for property damage or personal injury caused by such events; and whether we are subject to civil, criminal, or regulatory penalties in connection with such events; and whether our insurance coverage is available for these types of claims and sufficient to cover our liability;
- how the CPUC and the California Air Resources Board implement state environmental laws relating to greenhouse gases, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether we are able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations, and whether we are able to timely recover our associated investment costs;
- whether our climate change adaptation strategies are successful;
- the impact that reductions in customer demand for electricity and natural gas have on our ability to make and recover our investments through rates and earn our authorized return on equity, and whether we are successful in addressing the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services;
- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which we can manage and respond to the volatility of energy commodity prices; our ability and the ability of our counterparties to post or return collateral in connection with price risk management activities; and whether we are able to recover timely our electric generation and energy commodity costs through rates, including our renewable energy procurement costs;
- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether we can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;
- our ability to access capital markets and other sources of financing in a timely manner on acceptable terms;
- changes in credit ratings which could result in increased borrowing costs especially if we were to lose our investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and
- the impact of changes in U.S. Generally Accepted Accounting Principles, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and our future financial condition, results of operations and cash flows, you should read the sections titled "Risk Factors" in the documents incorporated by reference in this prospectus supplement and the accompanying prospectus.

You should read this prospectus supplement, the accompanying prospectus and the documents that we incorporate by reference into this prospectus supplement and the accompanying prospectus, the documents that we have included as exhibits to the registration statement of which this prospectus supplement and the accompanying prospectus are a part and the documents that we refer to under the section of the accompanying prospectus titled "Where You Can Find More Information" completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statements. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus supplement or the date of the document incorporated by reference. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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## OUR COMPANY

We are one of the largest combination natural gas and electric utilities in the United States. We were incorporated in California in 1905 and are a subsidiary of PG&E Corporation. We provide natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers. The principal executive offices of PG&E Corporation and Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and the telephone number of Pacific Gas and Electric Company is (415) 973-7000.

## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our historical ratio of earnings to fixed charges for each of the fiscal years indicated and for the nine months ended September 30, 2016.

| Nine months ended September 30, 2016 | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| 1.57x | 1.67x | 2.55x | 2.23x | 2.24x | 2.51x |

For the purpose of computing our ratios of earnings to fixed charges, “earnings” represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). “Fixed charges” include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, allowance for funds used during construction debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

## USE OF PROCEEDS

We estimate that the net proceeds from this offering will be approximately $638.0 million, after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We expect to use the net proceeds from the offering for general corporate purposes, including to repay our outstanding commercial paper and for the redemption of variable rate pollution control bonds in an aggregate principal amount of $160 million with a maturity date of December 1, 2016. At November 23, 2016, the outstanding commercial paper was approximately $877.5 million, the weighted average yield on our outstanding commercial paper was approximately 0.71% per annum and the weighted average maturity on our outstanding commercial paper was 17.84 days.

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## CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2016, as adjusted to give effect to (i) the issuance and sale of the senior notes, and (ii) the use of net proceeds from this offering as set forth under "Use of Proceeds" in this prospectus supplement. This table should be read in conjunction with our consolidated financial statements and related notes as of and for the nine months ended September 30, 2016, incorporated by reference in this prospectus supplement and the accompanying prospectus. See "Where You Can Find More Information" in the accompanying prospectus.

| | As of September 30, 2016 | |
|---|---|---|
| | Actual | As Adjusted |
| | (in millions) | |
| Current Liabilities: | | |
| Short-term borrowings(1) | $ 981 | $ 753 |
| Total long-term debt classified as current(2) | $ 160 | $ 0 |
| Capitalization: | | |
| Long-term debt(3) | $16,179 | $ 16,572 |
| Shareholders' equity(4) | 17,830 | 17,830 |
| Total capitalization | $34,009 | $ 34,402 |

(1) Actual short-term borrowings primarily included commercial paper and as adjusted short-term borrowings includes the floating rate notes offered hereby and gives effect to the use of proceeds of this offering to repay a portion of our outstanding commercial paper.
(2) As adjusted total long-term debt classified as current gives effect to the use of proceeds of this offering for the redemption of $160 million principal amount of certain pollution control bonds. See "Use of Proceeds."
(3) Actual long-term debt consisted of $1,107 million of pollution control bonds and $15,072 million of senior notes and as adjusted long-term debt includes the senior notes offered hereby, in each case, net of any discounts and premiums.
(4) Includes $258 million of preferred stock without mandatory redemption provisions.

## DESCRIPTION OF THE SENIOR NOTES

### General

You should read the following information in conjunction with the statements under “Description of the Senior Notes” in the accompanying prospectus.

As used in this section, the terms “we,” “us” and “our” refer to Pacific Gas and Electric Company, and not to any of our subsidiaries.

The floating rate notes are being offered in the aggregate principal amount of $250,000,000 and will mature on November 30, 2017.

The 2046 notes are being offered in the aggregate principal amount of $400,000,000 and will mature on December 1, 2046.

We will issue the senior notes under an existing indenture, which was originally entered into on March 11, 2004 and amended and restated on April 22, 2005, between us and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A.), as trustee, as supplemented by supplemental indentures between us and the trustee. Please read the indenture because it, and not this description, defines your rights as holders of the senior notes. We have filed with the Securities and Exchange Commission a copy of the indenture as an exhibit to the registration statement of which this prospectus supplement and the accompanying prospectus are a part.

Pursuant to the Trust Indenture Act of 1939, as amended, or the 1939 Act, if a default occurs on the senior notes, The Bank of New York Mellon Trust Company, N.A. may be required to resign as trustee under the indenture if it has a conflicting interest (as defined in the 1939 Act), unless the default is cured, duly waived or otherwise eliminated within 90 days.

We may, without consent of the holders of senior notes, issue additional notes under the indenture, having the same terms in all respects to either series of senior notes (except for the public offering price and the issue date and, in some cases, the first interest payment date) so that those additional notes will be consolidated and form a single series with the other outstanding senior notes of such series.

We will issue the senior notes in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The floating rate notes will not be redeemable prior to maturity.

The 2046 notes will be redeemable at our option, in whole or in part, at any time as described below under “Optional Redemption for 2046 Notes.”

Interest on the senior notes will be computed on the basis of a 360-day year consisting of twelve 30-day months.

We will issue the senior notes in the form of one or more global securities, which will be deposited with, or on behalf of, The Depository Trust Company, or DTC, and registered in the name of DTC’s nominee. Information regarding DTC’s book-entry system is set forth below under “Book-Entry System; Global Notes.”

Subject to applicable law (including, without limitation, United States federal securities laws), we or our affiliates may, at any time and from time to time, purchase outstanding senior notes by tender, in the open market or by private agreement.

**Ranking**

The senior notes will be our direct, unsecured and unsubordinated obligations and will rank equally with all our other existing and future unsecured and unsubordinated obligations. The senior notes will be effectively subordinated to all our secured debt. As of September 30, 2016, we had approximately $15.2 billion of notes outstanding under the indenture for senior notes. The indenture contains no restrictions on the amount of additional indebtedness that may be incurred by us.

As of September 30, 2016, we did not have any outstanding secured debt for borrowed money.

**Interest**

***Interest on Floating Rate Notes***

The floating rate notes will bear interest from December 1, 2016 or from the most recent date to which interest has been paid or provided for. We will pay interest on the floating rate notes quarterly on February 28, 2017, May 30, 2017, August 30, 2017 and November 30, 2017 (each, an "interest payment date"), to the persons in whose names the floating rate notes are registered at the close of business on the 15th calendar day (whether or not a Business Day) immediately preceding the related interest payment date; provided, however, that interest payable on the maturity date shall be payable to the person to whom the principal of such floating rate notes shall be payable. Interest on the floating rate notes will be computed on the basis of the actual number of days elapsed over a 360-day year. Notwithstanding anything to the contrary in this prospectus supplement, so long as the floating rate notes are in book-entry form, we will make payments of principal and interest through the trustee to DTC.

Interest payable on any interest payment date or the maturity date shall be the amount of interest accrued from, and including, the immediately preceding interest payment date in respect of which interest has been paid or duly provided for (or from and including the original issue date, if no interest has been paid or duly provided for with respect to the floating rate notes) to, but excluding, such interest payment date or maturity date, as the case may be. If any interest payment date (other than the maturity date) is not a Business Day at the relevant place of payment, we will pay interest on the next day that is a Business Day at such place of payment as if payment were made on the date such payment was due, and no interest will accrue on the amounts so payable for the period from and after such date to the immediately succeeding Business Day, except that if such Business Day is in the immediately succeeding calendar month, such interest payment date (other than the maturity date) shall be the immediately preceding Business Day. If the maturity date is not a Business Day at the relevant place of payment, we will pay interest, if any, and principal and premium, if any, on the next day that is a Business Day at such place of payment as if payment were made on the date such payment was due, and no interest will accrue for the intervening period.

"Business Day" means any day (1) that is not a Saturday or Sunday and that is not a day on which banking institutions are authorized or obligated by law or executive order to close in The City of New York and, for any place of payment outside of The City of New York, in such place of payment, and (2) that is also a "London business day", which is a day on which dealings in deposits in U.S. dollars are transacted in the London interbank market.

***Rate of Interest***

The interest rate on the floating rate notes will be reset quarterly on February 28, 2017, May 30, 2017 and August 30, 2017 (each, an "interest reset date"). The floating rate notes will bear interest at a per annum rate equal to three-month LIBOR (as defined below) for the applicable interest reset period or initial interest period (each as defined below) plus 0.20% (20 basis points). The interest rate for the initial interest period will be three-month LIBOR, determined as of two London business days prior to the original issue date, plus 0.20% (20 basis points) per annum. The interest rate on the floating rate notes will in no event be higher than the maximum rate

permitted by California law as the same may be modified by United States law of general application. Additionally, the interest rate on the floating rate notes will in no event be lower than zero.

The "initial interest period" will be the period from and including the original issue date to but excluding the initial interest reset date. Thereafter, each "interest reset period" will be the period from and including an interest reset date to but excluding the immediately succeeding interest reset date; provided that the final interest reset period for the floating rate notes will be the period from and including the interest reset date immediately preceding the maturity date of such floating rate notes to but excluding the maturity date.

If any interest reset date would otherwise be a day that is not a Business Day, the interest reset date will be postponed to the immediately succeeding day that is a Business Day, except that if that Business Day is in the immediately succeeding calendar month, the interest reset date shall be the immediately preceding Business Day.

The interest rate in effect on each day will be (i) if that day is an interest reset date, the interest rate determined as of the interest determination date (as defined below) immediately preceding such interest reset date or (ii) if that day is not an interest reset date, the interest rate determined as of the interest determination date immediately preceding the most recent interest reset date or the original issue date, as the case may be.

***Interest Rate Determination***

The interest rate applicable to each interest reset period commencing on the related interest reset date, or the original issue date in the case of the initial interest period, will be the rate determined as of the applicable interest determination date. The "interest determination date" will be the second London business day immediately preceding the original issue date, in the case of the initial interest reset period, or thereafter, will be the second London business day immediately preceding the applicable interest reset date.

The Bank of New York Mellon Trust Company, N.A., or its successor appointed by us, will act as calculation agent. Three-month LIBOR will be determined by the calculation agent as of the applicable interest determination date in accordance with the following provisions:

(i) LIBOR is the rate for deposits in U.S. dollars for the three-month period which appears on Reuters Screen LIBOR01 Page (as defined below) at approximately 11:00 a.m., London time, on the applicable interest determination date. "Reuters Screen LIBOR01 Page" means the display designated on page "LIBOR01" on Reuters Screen (or such other page as may replace the LIBOR01 page on that service, any successor service or such other service or services as may be nominated by the British Bankers' Association for the purpose of displaying London interbank offered rates for U.S. dollar deposits). If no rate appears on Reuters Screen LIBOR01 Page, LIBOR for such interest determination date will be determined in accordance with the provisions of paragraph (ii) below.

(ii) With respect to an interest determination date on which no rate appears on Reuters Screen LIBOR01 Page as of approximately 11:00 a.m., London time, on such interest determination date, the calculation agent shall request the principal London offices of each of four major reference banks (which may include affiliates of the underwriters) in the London interbank market selected by us to provide the calculation agent with a quotation of the rate at which deposits of U.S. dollars having a three-month maturity, commencing on the second London business day immediately following such interest determination date, are offered by it to prime banks in the London interbank market as of approximately 11:00 a.m., London time, on such interest determination date in a principal amount equal to an amount of not less than U.S. $1,000,000 that is representative for a single transaction in such market at such time. If at least two such quotations are provided, LIBOR for such interest determination date will be the arithmetic mean of such quotations as calculated by the calculation agent. If fewer than two quotations are provided, LIBOR for such interest determination date will be the arithmetic mean of the rates quoted as of approximately 11:00 a.m., New York City time, on such interest determination date by three major banks (which may include affiliates of the underwriters) selected by us for loans in U.S. dollars to leading

European banks having a three-month maturity commencing on the second London business day immediately following such interest determination date and in a principal amount equal to an amount of not less than U.S. $1,000,000 that is representative for a single transaction in such market at such time; provided, however, that if the banks selected as aforesaid by us are not quoting such rates as mentioned in this sentence, LIBOR for such interest determination date will be LIBOR determined with respect to the immediately preceding interest determination date.

All percentages resulting from any calculation of any interest rate for the floating rate notes will be rounded, if necessary, to the nearest one hundred thousandth of a percentage point, with five one-millionths of a percentage point rounded upward (e.g., 9.876545% (or .09876545) would be rounded to 9.87655% (or .0987655)), and all dollar amounts will be rounded to the nearest cent, with one-half cent being rounded upward.

Promptly upon such determination, the calculation agent will notify us and the trustee (if the calculation agent is not the trustee) of the interest rate for the new interest reset period. Upon request of a holder of the floating rate notes, the calculation agent will provide to such holder the interest rate in effect on the date of such request and, if determined, the interest rate for the next interest reset period.

All calculations made by the calculation agent for the purposes of calculating interest on the floating rate notes shall be conclusive and binding on the holders and us, absent manifest errors.

***Interest on 2046 Notes***

The 2046 notes will bear interest from December 1, 2016 at 4.00% per annum, payable semiannually on each June 1 and December 1, commencing on June 1, 2017 to holders of record at the close of business on May 15 and November 15 immediately preceding the interest payment date.

If any payment date falls on a day that is not a business day, the payment will be made on the next business day, but we will consider that payment as being made on the date that the payment was due to you. In that event, no interest will accrue on the amount payable for the period from and after such payment date to such next business day.

**No Redemption for Floating Rate Notes**

The floating rate notes will not be redeemable prior to maturity.

**Optional Redemption for 2046 Notes**

At any time prior to June 1, 2046 (the date that is six months prior to the maturity date), we may, at our option, redeem the 2046 notes in whole or in part at a redemption price equal to the greater of:

- 100% of the principal amount of the 2046 notes to be redeemed; or
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2046 notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) calculated as if the maturity date of the 2046 notes was June 1, 2046 (the date that is six months prior to the maturity date), discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate plus 20 basis points,

plus, in either case, accrued and unpaid interest to, but not including, the redemption date.

At any time on or after June 1, 2046 (the date that is six months prior to the maturity date), we may redeem the 2046 notes, in whole or in part, at 100% of the principal amount of the 2046 notes being redeemed plus accrued and unpaid interest to, but not including, the redemption date.

As used in this section "Optional Redemption for 2046 Notes," the following terms shall have the following meanings:

"Adjusted Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date.

"Business Day" means any day that is not a day on which banking institutions in New York City are authorized or required by law or regulation to close.

"Comparable Treasury Issue" means the United States Treasury security selected by the applicable Quotation Agent as having a maturity comparable to the remaining term of the 2046 notes to be redeemed, assuming, for such purpose, that the 2046 notes matured on June 1, 2046 (the date that is six months prior to the maturity date (the "remaining term"), that would be used, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the 2046 notes to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date:

- the average of the Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest of the Reference Treasury Dealer Quotations; or
- if we obtain fewer than four Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations so received.

"Quotation Agent" means the Reference Treasury Dealer appointed by us for the 2046 notes.

"Reference Treasury Dealer" means (1) each of Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA Inc. and their respective successors, unless any of them ceases to be a primary dealer in certain U.S. government securities ("Primary Treasury Dealer"), in which case we shall substitute another Primary Treasury Dealer; and (2) any other Primary Treasury Dealer selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that redemption date.

The redemption price will be calculated assuming a 360-day year consisting of twelve 30-day months.

We will send notice of any redemption at least 10 days but not more than 60 days before the redemption date to each registered holder of the 2046 notes to be redeemed.

Unless we default in payment of the redemption price, on and after the redemption date, interest will cease to accrue on the 2046 notes or portions of the 2046 notes called for redemption.

If we redeem only some of the 2046 notes, DTC's practice is to choose by lot the amount to be redeemed from the 2046 notes held by each of its participating institutions. DTC will give notice to these participants, and these participants will give notice to any "street name" holders of any indirect interests in the 2046 notes to be redeemed according to arrangements among them. These notices may be subject to statutory or regulatory requirements. We will not be responsible for giving notice of a redemption of the 2046 notes to be redeemed to anyone other than the registered holders of the 2046 notes to be redeemed, which is currently DTC. If 2046 notes to be redeemed are no longer held through DTC and fewer than all the 2046 notes are to be redeemed, selection of 2046 notes for redemption will be made by the trustee in any manner the trustee deems fair and appropriate.

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**No Sinking Fund for Senior Notes**

There is no provision for a sinking fund for the senior notes.

**Covenants**

The indenture restricts us and any of our subsidiaries which are "significant subsidiaries" from incurring or assuming secured debt or entering into sale and leaseback transactions, except in certain circumstances. The accompanying prospectus describes this covenant (see "Description of the Senior Notes—Restrictions on Liens and Sale and Leaseback Transactions" in the accompanying prospectus) and other covenants contained in the indenture in greater detail and should be read prior to investing.

**Book-Entry System; Global Notes**

Each series of senior notes will initially be issued in the form of one or more global notes. Each series of senior notes will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered security certificate will be issued for each series of senior notes in the aggregate principal amount of such series of senior notes, and will be deposited with DTC or the trustee on behalf of DTC and registered in the name of DTC or its nominee. If, however, the aggregate principal amount of a series exceeds $500 million, one certificate will be issued with respect to each $500 million of principal amount of such series and an additional certificate will be issued with respect to any remaining principal amount of such series. Investors may hold their beneficial interests in a global note directly through DTC or indirectly through organizations which are participants in the DTC system.

## CERTAIN UNITED STATES FEDERAL INCOME TAX CONSEQUENCES

The following summary describes certain United States federal income tax consequences of the acquisition, ownership and disposition of the senior notes as of the date hereof. This summary is based on the Internal Revenue Code of 1986, as amended, as well as final, temporary and proposed Treasury regulations and administrative and judicial decisions. Legislative, judicial and administrative changes may occur, possibly with retroactive effect, that could affect the accuracy of the statements described herein. This summary generally is addressed only to original purchasers of the senior notes that purchase the senior notes at the initial offering price, deals only with senior notes held as capital assets and does not purport to address all United States federal income tax matters that may be relevant to investors in special tax situations, such as insurance companies, tax-exempt organizations, financial institutions, dealers in securities or currencies, traders in securities that elect to mark to market, holders of senior notes that are held as a hedge or as part of a hedging, straddle or conversion transaction, certain former citizens or residents of the United States, or United States holders (as defined below) whose functional currency is not the United States dollar. **Persons considering the purchase of the senior notes should consult their own tax advisors concerning the application of United States federal income tax laws, as well as the laws of any state, local or foreign taxing jurisdictions, to their particular situations.**

If a partnership (including an entity treated as a partnership for United States federal income tax purposes) is a beneficial owner of a senior note, the treatment of such partnership, or a partner in the partnership, will generally depend upon the status of the partner and upon the activities of the partnership. A beneficial owner of a senior note that is a partnership, and partners in such a partnership, should consult their tax advisors about the United States federal income tax consequences of holding and disposing of the senior notes.

### United States Holders

This section describes the tax consequences to a United States holder. A "United States holder" is a beneficial owner of a senior note that is (i) a citizen or resident of the United States, (ii) a corporation (including an entity treated as a corporation for United States federal income tax purposes) created or organized in the United States or any state (including the District of Columbia), (iii) an estate whose income is subject to United States federal income tax on a net income basis in respect of the senior note, or (iv) a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorized to control all substantial decisions of the trust (or certain trusts that have made a valid election to be treated as a United States person).

If you are not a United States holder, this section does not apply to you. See "Non-United States Holders" below.

#### *Interest on Senior Notes*

*Floating Rate Notes*. Because the maturity date of the floating rate notes is not more than one year, interest on a floating rate note will be taxable to a United States holder of a floating rate note in accordance with the rules applicable to short-term debt obligations. In general, under those rules, a United States holder of a floating rate note who reports income for federal income tax purposes on the accrual method and certain other United States holders will be required to include the stated interest on such floating rate note in income on a straight-line basis, unless an election is made to accrue the stated interest according to a constant interest method based on daily compounding. A United States holder of a floating rate note who reports income for United States federal income tax purposes on the cash method will be required to include the stated interest in income at the time it is actually or constructively received unless such holder makes an election to include the stated interest in income currently as it accrues. Non-electing cash method United States holders will be required to defer deductions for any interest paid on indebtedness incurred or continued to purchase or carry such floating rate notes in an amount not exceeding the deferred interest income, until such deferred interest income is realized.

*2046 Notes*. The 2046 notes will not be issued with more than a *de minimis* amount of original issue discount for United States federal income tax purposes. Interest on a 2046 note will therefore be taxable to a United States holder as ordinary interest income at the time it accrues or is received, in accordance with the United States holder's method of accounting for United States federal income tax purposes.

***Sale, Exchange or Retirement of Senior Notes***

*Floating Rate Notes*. Upon the sale, exchange, retirement or other taxable disposition of a floating rate note, a United States holder will recognize taxable gain or loss equal to the difference between the amount realized from the sale, exchange, retirement or other taxable disposition and the United States holder's adjusted tax basis in the floating rate note. Such gain or loss generally will be short-term capital gain or loss, except in the case of a United States holder who is not required and does not elect to include interest in income currently in which case any gain realized on the sale, exchange, retirement or other taxable disposition of such a floating rate note will be treated as ordinary income to the extent of the unpaid interest that has accrued on a straight-line basis (or, if elected, according to a constant interest method based on daily compounding) through the date of such disposition. Capital losses are subject to certain limitations. A United States holder's adjusted tax basis in a floating rate note should equal the cost for the floating rate note, and in the case of an accrual method holder (or cash method holder that has elected to include interest in income currently) decreased by any payment of stated interest previously received and increased by any stated interest previously accrued.

*2046 Notes*. Upon the sale, exchange, retirement or other taxable disposition of a 2046 note, a United States holder will recognize taxable gain or loss equal to the difference between the amount realized from the sale, exchange, retirement or other taxable disposition (other than amounts attributable to accrued interest not previously included in income, which will be taxable as ordinary interest income) and the United States holder's adjusted tax basis in the 2046 note. A United States holder's adjusted tax basis in a 2046 note will generally equal the cost of the 2046 note to such holder increased by the amount of any accrued but unpaid interest previously included in income. Such gain or loss generally will be capital gain or loss, and will be long-term capital gain or loss if the 2046 note has been held for more than one year. Capital losses are subject to certain limitations.

***Tax on Net Investment Income***

Certain non-corporate United States holders of senior notes generally will be subject to a 3.8% tax on their net investment income for the relevant taxable year. Subject to certain exceptions, a United States holder's calculation of its net investment income generally will include its interest income on, and its net gains from the disposition of, the senior notes. A United States holder that is an individual, estate or trust is urged to consult its tax advisor regarding the applicability of this tax to its income and gains in respect of your investment in the senior notes.

**Non-United States Holders**

This section describes the tax consequences to a non-United States holder. You are a "non-United States holder" if you are the beneficial owner of a senior note (other than a partnership, including an entity treated as a partnership for United States federal income tax purposes) and are not a United States holder for United States federal income tax purposes.

***Interest***

A non-United States holder generally will not be subject to United States federal withholding tax with respect to payments of principal and interest on the senior notes, provided that (i) the non-United States holder does not actually or constructively own 10 percent or more of the total combined voting power of all classes of our stock entitled to vote, (ii) the non-United States holder is not for United States federal income tax purposes a controlled foreign corporation related to us (directly or indirectly) through stock ownership, and (iii) the

beneficial owner of the senior notes certifies to us or the fiscal and paying agent (on Internal Revenue Service Form W-8BEN, Form W-8BEN-E or other applicable form) under penalties of perjury as to its status as a non-United States holder and complies with applicable identification procedures. Special rules apply to partnerships, estates and trusts and, in certain circumstances, certifications as to foreign status and other matters may be required to be provided by partners and beneficiaries thereof.

***Sale, Exchange or Retirement of Senior Notes***

A non-United States holder of a senior note generally will not be subject to United States federal income tax on any gain realized upon the sale, exchange, retirement or other disposition of a senior note, unless the non-United States holder is an individual who is present in the United States for 183 days or more during the taxable year of sale, retirement or other disposition and certain other conditions are met. In such case, the non-United States holder generally will be subject to a 30 percent tax on any capital gain recognized on the disposition of the senior notes, after being offset by certain United States source capital losses.

***United States Trade or Business***

If a non-United States holder of a senior note is engaged in a trade or business in the United States and income or gain from the senior note is effectively connected with the conduct of such trade or business, the non-United States holder will be exempt from withholding tax if appropriate certification has been provided, but will generally be subject to regular United States federal income tax on such income and gain in the same manner as if it were a United States holder. In addition, if such non-United States holder is a foreign corporation, it may be subject to a branch profits tax equal to 30 percent (or lower applicable treaty rate) of its effectively connected earnings and profits for the taxable year, subject to adjustments.

***Foreign Account Tax Compliance Act***

Sections 1471 through 1474 of the United States Internal Revenue Code, the Foreign Account Tax Compliance Act or FATCA provisions, impose a 30 percent United States withholding tax on certain types of payments made to certain foreign entities. Failure to comply with the additional certification, information reporting and other specified requirements imposed under FATCA could result in United States withholding tax being imposed on payments of interest and principal under the senior notes and sales proceeds of the senior notes held by or through a foreign entity. United States Treasury Regulations and applicable guidance provide that FATCA withholding generally applies to payments of interest, and will apply to (i) gross proceeds from the sale, exchange or retirement of debt obligations paid after December 31, 2018, and (ii) certain pass-thru payments received with respect to debt obligations held through foreign financial institutions beginning on the later of January 1, 2019 and the date that applicable final regulations are issued. Prospective investors should consult their own tax advisors regarding FATCA and its effect on them.

**Backup Withholding and Information Reporting**

In general, payments of interest and the proceeds of sale, exchange, retirement or other disposition of the senior notes payable by a United States paying agent or other United States intermediary will be subject to information reporting. With respect to a non-United States holder, we must report annually to the Internal Revenue Service and to each non-United States holder the amount of any interest paid to such holder regardless of whether any tax was actually withheld. Copies of the information returns reporting such interest payments to a non-United States holder and the amount of any tax withheld also may be made available to the tax authorities in the country in which the non-United States holder resides under the provisions of an applicable income tax treaty. In addition, backup withholding at the then applicable rate (currently 28 percent) will generally apply to these payments if:

- in the case of a United States holder, the holder fails to provide an accurate taxpayer identification number, fails to certify that the holder is not subject to backup withholding or fails to report all interest and dividends required to be shown on its United States federal income tax returns; or

- in the case of a non-United States holder, the holder fails to provide the certification on Internal Revenue Service Form W-8BEN, Form W-8BEN-E or other applicable form or otherwise does not provide evidence of exempt status.

Certain United States holders (including, among others, corporations) are not subject to information reporting or backup withholding. Any amount paid as backup withholding will be creditable against the holder's United States federal income tax liability and may entitle the holder to a refund, provided that the required information is timely furnished to the Internal Revenue Service. Holders of the senior notes should consult their tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining such an exemption.

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## UNDERWRITING

Subject to the terms and conditions set forth in an underwriting agreement between us and the underwriters named below, for whom Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA Inc. are acting as representatives, we have agreed to sell to each of the underwriters, and each of the underwriters has severally and not jointly agreed to purchase from us, the principal amount of senior notes set forth opposite its name below.

| Underwriter | Principal Amount of Floating Rate Notes | Principal Amount of 2046 Notes |
|---|---|---|
| Citigroup Global Markets Inc. | $ 43,750,000 | $ 70,000,000 |
| J.P. Morgan Securities LLC | 43,750,000 | 70,000,000 |
| Merrill Lynch, Pierce, Fenner & Smith Incorporated | 43,750,000 | 70,000,000 |
| Mizuho Securities USA Inc. | 43,750,000 | 70,000,000 |
| CIBC World Markets Corp. | 15,000,000 | 24,000,000 |
| SMBC Nikko Securities America, Inc. | 15,000,000 | 24,000,000 |
| U.S. Bancorp Investments, Inc. | 15,000,000 | 24,000,000 |
| Lebenthal & Co., LLC | 10,000,000 | 16,000,000 |
| Mischler Financial Group, Inc. | 10,000,000 | 16,000,000 |
| Samuel A. Ramirez & Company, Inc. | 10,000,000 | 16,000,000 |
| Total | $ 250,000,000 | $400,000,000 |

The underwriters have agreed, subject to the terms and conditions set forth in the underwriting agreement, to purchase all of the senior notes if any of the senior notes are purchased.

The underwriters propose to offer the senior notes directly to the public at the public offering price specified on the cover page to this prospectus supplement and may also offer the senior notes to certain dealers at the public offering price less a concession not to exceed 0.100% of the principal amount of the floating rate notes and 0.500% of the principal amount of the 2046 notes. The underwriters may allow, and these dealers may reallow, concession to certain brokers and dealers not to exceed 0.050% of the principal amount of the floating rate notes and 0.250% of the principal amount of the 2046 notes. After the initial offering of the senior notes, the underwriters may change the offering price and concession.

The senior notes have no established trading market. We currently have no intention to apply to list the senior notes on any securities exchange or automated dealer quotation system. The underwriters may make a market in the senior notes after completion of the offering, but will not be obligated to make a market in the senior notes and may discontinue such market making at any time without notice. No assurance can be given as to the liquidity of the trading market for the senior notes or that an active public market for the senior notes will develop. If an active public trading market for the senior notes does not develop, the market price and liquidity of the senior notes may be adversely affected.

We will agree to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or to contribute to payments which the underwriters may be required to make in respect thereof.

We estimate our expenses for this offering, other than the underwriting discounts and commissions, to be approximately $1 million.

We will agree with the underwriters not to, during the period three business days from the date of the underwriting agreement, sell, offer to sell, grant any option for the sale of, or otherwise dispose of any debt securities other than the senior notes, without the prior written consent of each of Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA Inc. This agreement will not apply to issuances of commercial paper or other debt securities with scheduled

maturities of less than one year and the sale or remarketing of tax-exempt bonds issued by a governmental authority or body for our benefit.

In order to facilitate the offering, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the senior notes. Specifically, the underwriters may over-allot in connection with the offering, creating short positions in the senior notes for their own accounts. In addition, to cover over-allotments or to stabilize the price of the senior notes, the underwriters may bid for, and purchase, senior notes in the open market. The underwriters may reclaim selling concessions allowed to an underwriter or dealer for distributing senior notes in the offering if the underwriters repurchase previously distributed senior notes in transactions to cover short positions, in stabilization transactions or otherwise. Any of these activities may stabilize or maintain the market price of the senior notes above independent market levels. The underwriters are not required to engage in these activities and may end any of these activities at any time without notice.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased notes sold by or for the account of such underwriter in stabilizing or short covering transactions.

In general, purchases of a security for the purpose of stabilization or to reduce a short position could cause the price of the security to be higher than it might be in the absence of such purchases. The imposition of a penalty bid might also have an effect on the price of a security to the extent that it were to discourage resales of the security.

Neither we nor any underwriter makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the senior notes. In addition, neither we nor any underwriter makes any representation that the underwriters will engage in such transactions or that such transactions once commenced will not be discontinued without notice.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their affiliates have engaged and may in the future engage in transactions with, and, from time to time, have performed and may perform investment banking, corporate trust and/or commercial banking services for, us and certain of our affiliates in the ordinary course of business, for which they have received and will receive customary compensation. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments including serving as counterparties to certain derivative and hedging arrangements and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. Certain of the underwriters or their respective affiliates that have a lending relationship with us routinely hedge, and certain other of those underwriters or their respective affiliates may hedge, their credit exposure to us consistent with their customary risk management policies. Typically, these underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the notes offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the notes offered hereby. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments. Citigroup Global Markets Inc., J.P. Morgan Securities LLC and Mizuho Securities USA Inc. are dealers under our commercial paper program and other underwriters or their affiliates may hold our commercial paper and may receive a portion of the net proceeds from this offering. Additionally, affiliates of one or more of the underwriters are part of a consortium of banks that participates in our revolving credit facility or Corp's revolving credit facility and may also hold our debt securities.

**Selling Restrictions**

***Notice to Prospective Investors in the European Economic Area***

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a "Relevant Member State"), each underwriter has represented and agreed that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State it has not made and will not make an offer of senior notes which are the subject of the offering contemplated by this prospectus supplement to the public in that Relevant Member State other than:

(a) to any legal entity which is a qualified investor as defined in the Prospectus Directive;

(b) to fewer than 150 natural or legal persons (other than qualified investors as defined in the Prospectus Directive), subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the issuer for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of senior notes shall require the issuer or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive or supplement a prospectus pursuant to Article 16 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of senior notes to the public" in relation to any senior notes in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the senior notes to be offered so as to enable an investor to decide to purchase or subscribe the senior notes, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State, the expression "Prospectus Directive" means Directive 2003/71/EC (as amended, including by Directive 2010/73/EU), and includes any relevant implementing measure in the Relevant Member State.

***Notice to Prospective Investors in the United Kingdom***

This communication is only being distributed to and is only directed at (i) persons who are outside the United Kingdom or (ii) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (iii) high net worth companies, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as "relevant persons"). The senior notes are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such senior notes will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this prospectus supplement and the accompanying prospectus or any of their contents.

Each underwriter has represented, warranted and agreed that:

1.1 it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000 (the "FSMA")) received by it in connection with the issue or sale of the senior notes in circumstances in which Section 21(1) of the FSMA would not, if the issuer was not an authorised person apply to the issuer; and

1.2 it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the senior notes in, from or otherwise involving the United Kingdom.

***Notice to Prospective Investors in Switzerland***

The senior notes may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("SIX") or on any other stock exchange or regulated trading facility in Switzerland. This prospectus

supplement does not constitute a prospectus within the meaning of, and has been prepared without regard to the disclosure standards for issuance prospectuses under art. 652a or art. 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under art. 27 ff. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither this prospectus supplement nor any other offering or marketing material relating to the senior notes or the offering may be publicly distributed or otherwise made publicly available in Switzerland.

Neither this prospectus supplement nor any other offering or marketing material relating to the offering, the Company or the senior notes have been or will be filed with or approved by any Swiss regulatory authority. In particular, this prospectus supplement will not be filed with, and the offer of senior notes will not be supervised by, the Swiss Financial Market Supervisory Authority ("FINMA"), and the offer of senior notes has not been and will not be authorized under the Swiss Federal Act on Collective Investment Schemes ("CISA"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of the senior notes.

***Notice to Residents of Canada***

The senior notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the senior notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus supplement (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

***Notice to Prospective Investors in Hong Kong***

The senior notes may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the senior notes may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to senior notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

***Notice to Prospective Investors in Singapore***

This prospectus supplement has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus supplement and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the senior notes may not be circulated or distributed, nor may the senior notes be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the senior notes are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the senior notes under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

***Notice to Prospective Investors in Japan***

The senior notes have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any senior notes, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

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## GENERAL INFORMATION

The notes have been accepted for clearance through DTC and have been assigned the following identification number:

| | CUSIP Number | ISIN |
|---|---|---|
| Floating rate notes | 694308HQ3 | US694308HQ36 |
| 2046 notes | 694308HR1 | US694308HR19 |

## LEGAL MATTERS

The validity of the senior notes will be passed upon for us by Orrick, Herrington & Sutcliffe LLP, San Francisco, California. Skadden, Arps, Slate, Meagher & Flom LLP, New York, New York represents the underwriters. Skadden, Arps, Slate, Meagher & Flom LLP has in the past performed legal services in connection with federal regulatory and transactional matters for us and our affiliates.

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**PROSPECTUS**

# Pacific Gas and Electric Company

## Senior Notes

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We may offer and sell from time to time an indeterminate principal amount of senior notes in one or more offerings. This prospectus provides you with a general description of the senior notes that may be offered.

Each time we sell senior notes, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior notes. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should carefully read this prospectus and any applicable prospectus supplement for the specific offering before you invest in any of the senior notes. This prospectus may not be used to sell senior notes unless accompanied by a prospectus supplement.

The senior notes may be sold to or through underwriters, dealers or agents or directly to other purchasers. A prospectus supplement will set forth the names of any underwriters, dealers or agents involved in the sale of the senior notes, the aggregate principal amount of senior notes to be purchased by them and the compensation they will receive.

**See "Risk Factors" on page 1 for information on certain risks related to the purchase of our securities.**

**None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.**

February 11, 2014

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## ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or the SEC, using a shelf registration process. Under this shelf registration process, we may from time to time sell an indeterminate principal amount of senior notes in one or more offerings.

This prospectus provides you with only a general description of the senior notes that we may offer. This prospectus does not contain all of the information set forth in the registration statement of which this prospectus is a part, as permitted by the rules and regulations of the SEC. For additional information regarding us and the offered senior notes, please refer to the registration statement of which this prospectus is a part. Each time we sell senior notes, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior notes. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should rely only on the information in the applicable prospectus supplement if this prospectus and the applicable prospectus supplement are inconsistent. Before purchasing any senior notes, you should carefully read both this prospectus and the applicable prospectus supplement, together with the additional information described under the section of this prospectus titled "Where You Can Find More Information." In particular, you should carefully consider the risks and uncertainties described under the section titled "Risk Factors" or otherwise included in any applicable prospectus supplement or incorporated by reference in this prospectus before you decide whether to purchase the senior notes. These risks and uncertainties, together with those not known to us or those that we may deem immaterial, could impair our business and ultimately affect our ability to make payments on the senior notes.

You should rely only on the information contained or incorporated by reference in this prospectus and in any applicable prospectus supplement. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. Neither we nor any underwriter, dealer or agent will make an offer to sell the senior notes in any jurisdiction where the offer or sale is not permitted. You should assume that the information in this prospectus and any applicable prospectus supplement is accurate only as of the dates on their covers. Our business, financial condition, results of operations and prospects may have changed since those dates.

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## PACIFIC GAS AND ELECTRIC COMPANY

We are a public utility serving more than 15 million people throughout 70,000 square miles in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers.

We were incorporated in California in 1905. Our principal executive offices are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and our telephone number at that location is (415) 973-7000.

Unless otherwise indicated, when used in this prospectus, the terms "we," "our," "ours" and "us" refer to Pacific Gas and Electric Company and its subsidiaries, and the term "Corp" refers to our parent, PG&E Corporation.

## RISK FACTORS

Investing in our securities involves risk. Please see risk factors described in our Annual Report on Form 10-K and other reports filed with the SEC, which are all incorporated by reference in this prospectus. Before making an investment decision, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus or the applicable supplement to this prospectus. The risks and uncertainties described are not the only ones facing us. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations, financial results and the value of our securities.

## FORWARD-LOOKING STATEMENTS

This prospectus, the documents incorporated by reference in this prospectus and any applicable prospectus supplement contain forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts as of the date of this prospectus. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations; forecasts of costs we will incur to make safety and reliability improvements, including natural gas transmission costs that we will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those related to environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- when and how the pending California Public Utilities Commission ("CPUC") investigations and enforcement matters related to our natural gas system operating practices and our natural gas transmission pipeline rupture and fire that occurred on September 9, 2010 in San Bruno, California (the "San Bruno accident") are concluded, including the ultimate amount of fines we will be required to pay to the State General Fund, the amount of natural gas transmission costs we will be prohibited from recovering, and the cost of any remedial actions we may be ordered to perform;
- the outcome of the pending federal criminal investigation related to the San Bruno accident, including the ultimate amount of civil or criminal fines or penalties, if any, we may be required to pay, and the impact of remedial measures we are required to take such as the appointment of an independent monitor;

- whether we are able to repair the reputational harm that we have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident and the decisions to be issued in the pending investigations, including any charge or finding of criminal liability;

- the outcomes of our ratemaking proceedings, such as the 2014 general rate case, the 2015 gas transmission and storage rate case, and the transmission owner rate cases;

- the amount and timing of additional common stock issuances by Corp, the proceeds of which are contributed as equity to maintain our authorized capital structure as we incur charges and costs that we cannot recover through rates, including costs and fines associated with natural gas matters and the pending investigations;

- the outcome of future regulatory investigations, citations, or other proceedings, that may be commenced relating to our compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of our electric and gas facilities;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge our known and unknown remediation obligations; the extent to which we are able to recover environmental compliance and remediation costs in rates or from other sources; and the ultimate amount of environmental remediation costs we incur but do not recover, such as the remediation costs associated with our natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or Nuclear Regulatory Commission ("NRC") regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; and whether we decide to request that the NRC resume processing our renewal application for the two Diablo Canyon nuclear power plant operating licenses, and if so, whether the NRC grants the renewal;

- the impact of weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt our service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by us, our customers, or third parties on which we rely; and subject us to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on us;

- the impact of environmental laws and regulations aimed at the reduction of carbon dioxide and greenhouse gases, and whether we are able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline in our service area, general and regional economic and financial market conditions, the extent of municipalization of our electric or gas distribution facilities, changing levels of "direct access" customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators," and the development of alternative energy technologies including self-generation, storage and distributed generation technologies;

- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; the extent to which we can manage and respond to the volatility of energy commodity prices; the ability of us and our counterparties to post or return collateral in connection with price risk management activities; and whether we are able to recover timely our energy commodity costs through rates;

- whether our information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether we are able to protect our operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether our security measures are sufficient to protect confidential customer, vendor, and financial data contained in such systems and networks; and whether we can continue to rely on third-party vendors and contractors that maintain and support some of our operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- Corp's and our ability to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if we were to lose our investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, or regulations; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the more significant risks that could affect the outcome of these forward-looking statements and our future financial condition and results of operations, you should read the sections of the documents incorporated herein by reference titled "Risk Factors" as well as the important factors set forth under the heading "Risk Factors" in the applicable supplement to this prospectus.

You should read this prospectus, any applicable prospectus supplements, the documents that we incorporate by reference into this prospectus, the documents that we have included as exhibits to the registration statement of which this prospectus is a part and the documents that we refer to under the section of this prospectus titled "Where You Can Find More Information" completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statement. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus, the date of the document incorporated by reference or the date of any applicable prospectus supplement. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our historical ratios of earnings to fixed charges for the periods indicated:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | 2010 | 2009 |
| Ratio of earnings to fixed charges | 2.23x | 2.24x | 2.51x | 3.12x | 3.12x |

For the purpose of computing the ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases and allowance for funds used during construction related to the cost of debt and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

## USE OF PROCEEDS

Each prospectus supplement will describe the uses of the proceeds from the issuance of the senior notes offered by that prospectus supplement.

## DESCRIPTION OF THE SENIOR NOTES

This prospectus describes certain general terms of the senior notes that we may sell from time to time under this prospectus. We will describe the specific terms of each series of senior notes we offer in a prospectus supplement. The senior notes will be issued under an indenture dated as of April 22, 2005 (which supplemented, amended and restated the original indenture dated as of March 11, 2004 as thereafter supplemented) and one or more supplemental indentures that we will enter into with The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A. and successor to BNY Western Trust Company), as trustee. We have summarized selected provisions of the indenture and the senior notes below. The information we are providing you in this prospectus concerning the senior notes and the indenture is only a summary of the information provided in those documents, and the summary is qualified in its entirety by reference to the provisions of the indenture, including the forms of senior notes attached thereto. You should consult the senior notes themselves and the indenture for more complete information on the senior notes as they, and not this prospectus or any prospectus supplement, govern your rights as a holder. The indenture is included as an exhibit to the registration statement of which this prospectus is a part. The indenture has been qualified under the Trust Indenture Act of 1939, as amended, or the Trust Indenture Act, and the terms of the senior notes will include those made part of the indenture by the Trust Indenture Act.

In this section, references to “we,” “our,” “ours” and “us” refer only to Pacific Gas and Electric Company and not to any of its direct or indirect subsidiaries or affiliates except as expressly provided.

### General

The senior notes are our unsecured general obligations and will rank equally in right of payment to all our other senior and unsubordinated debt. The senior notes will be entitled to the benefit of the indenture equally and ratably with all other senior notes issued under the indenture.

The indenture does not limit the amount of debt we may issue under it or the amount of debt we or our subsidiaries may otherwise incur. We may issue senior notes from time to time under the indenture in one or more series by entering into supplemental indentures or by resolution of our board of directors.

### Provisions of a Particular Series

The prospectus supplement applicable to each series of senior notes will specify, among other things:

- the title of the senior notes;
- any limit on the aggregate principal amount of the senior notes;
- the date or dates on which the principal of the senior notes is payable, including the maturity date, or the method or means by which those dates will be determined, and our right, if any, to extend those dates and the duration of any extension;
- the interest rate or rates of the senior notes, if any, which may be fixed or variable, or the method or means by which the interest rate or rates will be determined, and our ability to extend any interest payment periods and the duration of any extension;
- the date or dates from which any interest will accrue, the dates on which we will pay interest on the senior notes and the regular record date, if any, for determining who is entitled to the interest payable on any interest payment date;
- any periods or periods within which, or date or dates on which, the price or prices at which and the terms and conditions on which the senior notes may be redeemed, in whole or in part, at our option;

- any obligation of ours to redeem, purchase or repay the senior notes pursuant to any sinking fund or other mandatory redemption provisions or at the option of the holder and the terms and conditions upon which the senior notes will be so redeemed, purchased or repaid;
- the denominations in which we will authorize the senior notes to be issued, if other than $1,000 or integral multiples of $1,000;
- whether we will offer the senior notes in the form of global securities and, if so, the name of the depositary for any global securities;
- if the amount payable in respect of principal of or any premium or interest on any senior notes may be determined with reference to an index or other fact or event ascertainable outside the indenture, the manner in which such amount will be determined;
- covenants for the benefit of the holders of that series;
- the currency or currencies in which the principal, premium, if any, and interest on the senior notes will be payable if other than U.S. dollars and the method for determining the equivalent amount in U.S. dollars;
- if the principal of the senior notes is payable from time to time without presentation or surrender, any method or manner of calculating the principal amount that is outstanding at any time for purposes of the indenture; and
- any other terms of the senior notes.

We may sell senior notes at par or at a discount below their stated principal amount. We will describe in a prospectus supplement material U.S. federal income tax considerations, if any, and any other special considerations for any senior notes we sell that are denominated in a currency other than U.S. dollars.

**Payment**

Except as may be provided with respect to a series, interest, if any, on the senior notes payable on each interest payment date will be paid to the person in whose name that senior note is registered as of the close of business on the regular record date for the interest payment date. However, interest payable at maturity will be paid to the person to whom the principal is paid. If there has been a default in the payment of interest on any senior notes, the defaulted interest may be paid to the holders of the senior notes as of a date between 10 and 30 days before the date we propose for payment of defaulted interest or in any other manner not inconsistent with the requirements of any securities exchange on which those senior notes may be listed, if the trustee finds it practicable.

**Redemption**

Any terms for the optional or mandatory redemption of a series of senior notes will be set forth in a prospectus supplement for the offered series. Unless otherwise indicated in a prospectus supplement, senior notes will be redeemable by us only upon notice by mail not less than 30 nor more than 60 days before the date fixed for redemption and, if less than all the senior notes of a series are to be redeemed, the particular senior notes to be redeemed will be selected by the method provided for that particular series, or in the absence of any such provision, by such method of random selection as the registrar deems fair and appropriate.

We have reserved the right to provide conditional redemption notices for redemptions at our option or for redemptions that are contingent upon the occurrence or nonoccurrence of an event or condition that cannot be ascertained prior to the time we are required to notify holders of the redemption. A conditional notice may state that if we have not deposited redemption funds with the trustee or a paying agent on or before the redemption date or we have directed the trustee or paying agent not to apply money deposited with it for redemption of senior notes, we will not be required to redeem the senior notes on the redemption date.

**Restrictions on Liens and Sale and Leaseback Transactions**

The indenture does not permit us or any of our significant subsidiaries (as defined below) to, (i) issue, incur, assume or permit to exist any debt (as defined below) secured by a lien (as defined below) on any of our principal property (as defined below) or any of our significant subsidiaries' principal property, whether that principal property was owned when the original indenture was executed (March 11, 2004) or thereafter acquired, unless we provide that the senior notes will be equally and ratably secured with the secured debt or (ii) incur or permit to exist any attributable debt (as defined below) in respect of principal property; provided, however, that the foregoing restriction will not apply to the following:

- to the extent we or a significant subsidiary consolidates with, or merges with or into, another entity, liens on the property of the entity securing debt in existence on the date of the consolidation or merger, provided that the debt and liens were not created or incurred in anticipation of the consolidation or merger and that the liens do not extend to or cover any of our or a significant subsidiary's principal property;

- liens on property acquired after March 11, 2004 and existing at the time of acquisition, as long as the lien was not created or incurred in anticipation thereof and does not extend to or cover any other principal property;

- liens of any kind, including purchase money liens, conditional sales agreements or title retention agreements and similar agreements, upon any property acquired, constructed, developed or improved by us or a significant subsidiary (whether alone or in association with others) which do not exceed the cost or value of the property acquired, constructed, developed or improved and which are created prior to, at the time of, or within 12 months after the acquisition (or in the case of property constructed, developed or improved, within 12 months after the completion of the construction, development or improvement and commencement of full commercial operation of the property, whichever is later) to secure or provide for the payment of any part of the purchase price or cost thereof; provided that the liens do not extend to any principal property other than the property so acquired, constructed, developed or improved;

- liens in favor of the United States, any state or any foreign country or any department, agency or instrumentality or any political subdivision of the foregoing to secure payments pursuant to any contract or statute or to secure any indebtedness incurred for the purpose of financing all or any part of the purchase price or cost of constructing or improving the property subject to the lien, including liens related to governmental obligations the interest on which is tax-exempt under Section 103 of the Internal Revenue Code of 1986, as amended, or the Code, or any successor section of the Code;

- liens in favor of us, one or more of our significant subsidiaries, one or more of our wholly owned subsidiaries or any of the foregoing combination; and

- replacements, extensions or renewals (or successive replacements, extensions or renewals), in whole or in part, of any lien or of any agreement referred to in the bullet points above or replacements, extensions or renewals of the debt secured thereby (to the extent that the amount of the debt secured by the lien is not increased from the amount originally so secured, plus any premium, interest, fee or expenses payable in connection with any replacements, refundings, refinancings, remarketings, extensions or renewals); provided that replacement, extension or renewal is limited to all or a part of the same property (plus improvements thereon or additions or accessions thereto) that secured the lien replaced, extended or renewed.

Notwithstanding the restriction described above, we or any significant subsidiary may, (i) issue, incur or assume debt secured by a lien not described in the immediately preceding six bullet points on any principal property owned at March 11, 2004 or thereafter acquired without providing that the outstanding senior notes be equally and ratably secured with that debt and (ii) issue or permit to exist attributable debt in respect of principal property, in either case, so long as the aggregate amount of that secured debt and attributable debt, together with

the aggregate amount of all other debt secured by liens on principal property not described in the immediately preceding six bullet points then outstanding and all other attributable debt in respect of principal property, does not exceed 10% of our net tangible assets, as determined by us as of a month end not more than 90 days prior to the closing or consummation of the proposed transaction.

For these purposes:

- "attributable debt" in respect of a sale and leaseback transaction means, at the time of determination, the present value of the obligation of the lessee for net rental payments during the remaining term of the lease included in the sale and leaseback transaction, including any period for which the lease has been extended or may, at the option of the lessor, be extended. The present value shall be calculated using a discount rate equal to the rate of interest implicit in the transaction, determined in accordance with generally accepted accounting principals, or GAAP.

- "capital lease obligation" means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet in accordance with GAAP.

- "debt" means any debt of ours for money borrowed and guarantees by us of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- "debt" of a significant subsidiary means any debt of such significant subsidiary for money borrowed and guarantees by the significant subsidiary of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- "excepted property" means any right, title or interest of us or any of our significant subsidiaries in, to or under any of the following property, whether owned at March 11, 2004 or thereafter acquired:

  - all money, investment property and deposit accounts (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), and all cash on hand or on deposit in banks or other financial institutions, shares of stock, interests in general or limited partnerships or limited liability companies, bonds, notes, other evidences of indebtedness and other securities, of whatever kind and nature;

  - all accounts, chattel paper, commercial tort claims, documents, general intangibles, instruments, letter-of-credit rights and letters of credit (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), with certain exclusions such as licenses and permits to use the real property of others, and all contracts, leases (other than the lease of certain real property at our Diablo Canyon power plant), operating agreements and other agreements of whatever kind and nature; and all contract rights, bills and notes;

  - all revenues, income and earnings, all accounts receivable, rights to payment and unbilled revenues, and all rents, tolls, issues, product and profits, claims, credits, demands and judgments, including any rights in or to rates, revenue components, charges, tariffs, or amounts arising therefrom, or in any amounts that are accrued and recorded in a regulatory account for collection by us or any significant subsidiary;

  - all governmental and other licenses, permits, franchises, consents and allowances including all emission allowances (or similar rights) created under any similar existing or future law relating to abatement or control of pollution of the atmosphere, water or soil, other than all licenses and permits to use the real property of others, franchises to use public roads, streets and other public properties, rights of way and other rights, or interests relating to the occupancy or use of real property;

  - all patents, patent licenses and other patent rights, patent applications, trade names, trademarks, copyrights and other intellectual property, including computer software and software licenses;

- all claims, credits, choses in action, and other intangible property;
- all automobiles, buses, trucks, truck cranes, tractors, trailers, motor vehicles and similar vehicles and movable equipment; all rolling stock, rail cars and other railroad equipment; all vessels, boats, barges and other marine equipment; all airplanes, helicopters, aircraft engines and other flight equipment; and all parts, accessories and supplies used in connection with any of the foregoing;
- all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; all materials, supplies, inventory and other items of personal property that are consumable (otherwise than by ordinary wear and tear) in their use in the operation of the principal property; all fuel, whether or not that fuel is in a form consumable in the operation of the principal property, including separate components of any fuel in the forms in which those components exist at any time before, during or after the period of the use thereof as fuel; all hand and other portable tools and equipment; and all furniture and furnishings;
- all personal property the perfection of a security interest in which is not governed by the California Commercial Code;
- all oil, gas and other minerals (as those terms are defined in the California Commercial Code as in effect on March 11, 2004) and all coal, ore, gas, oil and other minerals and all timber, and all rights and interests in any of the foregoing, whether or not the minerals or timber have been mined or extracted or otherwise separated from the land; and all electric energy and capacity, gas (natural or artificial), steam, water and other products generated, produced, manufactured, purchased or otherwise acquired by us or any significant subsidiary;
- all property which is the subject of a lease agreement other than a lease agreement that results from a sale and leaseback transaction designating us or any significant subsidiary as lessee and all our, or a significant subsidiary's right, title and interest in and to that property and in, to and under that lease agreement, whether or not that lease agreement is intended as security (other than certain real property leased at our Diablo Canyon power plant and the related lease agreement);
- real, personal and mixed properties of an acquiring or acquired entity unless otherwise made a part of principal property; and
- all proceeds (as that term is defined in the California Commercial Code as in effect on March 11, 2004) of the property listed in the preceding bullet points;

- "lien" means any mortgage, deed of trust, pledge, security interest, encumbrance, easement, lease, reservation, restriction, servitude, charge or similar right and any other lien of any kind, including, without limitation, any conditional sale or other title retention agreement, any lease of a similar nature, and any defect, irregularity, exception or limitation in record title or, when the context so requires, any lien, claim or interest arising from anything described in this bullet point.
- "net tangible assets" means the total amount of our assets determined on a consolidated basis in accordance with GAAP, less (i) the sum of our consolidated current liabilities determined in accordance with GAAP and (ii) the amount of our consolidated assets classified as intangible assets determined in accordance with GAAP, including, but not limited to, such items as goodwill, trademarks, trade names, patents, and unamortized debt discount and expense and regulatory assets carried as an asset on our consolidated balance sheet.
- "principal property" means any property of ours or any of our significant subsidiaries, as applicable, other than excepted property.
- "significant subsidiary" has the meaning specified in Rule 1-02(w) of Regulation S-X under the Securities Act of 1933, as amended, or the Securities Act; provided that, significant subsidiary shall not include any corporation or other entity substantially all the assets of which are excepted property.

- "swap agreement" means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions.

**Consolidation, Merger, Conveyance or Other Transfer**

We may not consolidate with or merge with or into any other person (as defined below) or convey, otherwise transfer or lease all or substantially all of our principal property to any person unless:

- the person formed by that consolidation or into which we are merged or the person which acquires by conveyance or other transfer, or which leases, all or substantially all of the principal property is a corporation, partnership, limited liability company, association, company, joint stock company or business trust, organized and existing under the laws of the United States, or any state thereof or the District of Columbia;

- the person executes and delivers to the trustee a supplemental indenture that in the case of a consolidation, merger, conveyance or other transfer, or in the case of a lease if the term thereof extends beyond the last stated maturity of the senior notes then outstanding, contains an assumption by the successor person of the due and punctual payment of the principal of and premium, if any, and interest, if any, on all senior notes then outstanding and the performance and observance of every covenant and condition under the indenture to be performed or observed by us;

- in the case of a lease, the lease is made expressly subject to termination by us or by the trustee at any time during the continuance of an event of default under the indenture;

- immediately after giving effect to the transaction and treating any indebtedness that becomes our obligation as a result of the transaction as having been incurred by us at the time of the transaction, no default or event of default under the indenture shall have occurred and be continuing; and

- we have delivered to the trustee an officer's certificate and an opinion of counsel, each stating that the merger, consolidation, conveyance, lease or transfer, as the case may be, fully complies with all provisions of the indenture; provided, however, that the delivery of the officer's certificate and opinion of counsel shall not be required with respect to any merger, consolidation, conveyance, lease or transfer between us and any of our wholly owned subsidiaries.

Notwithstanding the foregoing, we may merge or consolidate with or transfer all or substantially all of our assets to an affiliate that has no significant assets or liabilities and was formed solely for the purpose of changing our jurisdiction of organization or our form of organization or for the purpose of forming a holding company; provided that the amount of our indebtedness is not increased; and provided, further that the successor assumes all of our obligations under the indenture.

In the case of the conveyance or other transfer of all or substantially all of our principal property to any person as contemplated under the indenture, upon the satisfaction of all the conditions described above, we (as we would exist without giving effect to the transaction) would be released and discharged from all obligations and covenants under the indenture and under the senior notes then outstanding unless we elect to waive the release and discharge.

The meaning of the term "substantially all" has not been definitely established and is likely to be interpreted by reference to applicable state law if and at the time the issue arises and will depend on the facts and circumstances existing at the time.

For these purposes, "person" means any individual, corporation, partnership, limited liability company, association, company, joint stock company, limited liability partnership, joint venture, trust or unincorporated organization, or any other entity whether or not a legal entity, or any governmental authority.

**Additional Covenants**

We have agreed in the indenture, among other things:

- to maintain a place of payment;
- to maintain our corporate existence (subject to the provisions above relating to mergers and consolidations); and
- to deliver to the trustee an annual officer's certificate with respect to our compliance with our obligations under the indenture.

**Modification of the Indenture; Waiver**

We and the trustee may, with the consent of the holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the indenture, considered as one class, modify or amend the indenture, including the provisions relating to the rights of the holders of senior notes of the affected series. However, no modification or amendment may, without the consent of each holder of affected senior notes:

- change the stated maturity (except as provided by the terms of a series of senior notes) of the principal of, or interest on, the senior note or reduce the principal amount or any premium payable on the senior note or reduce the interest rate of the senior note, or change the method of calculating the interest rate with respect to the senior note;
- reduce the amount of principal of any discount senior note that would be payable upon acceleration of the maturity of the senior note;
- change the coin, currency or other property in which the senior note or interest or premium on the senior note is payable;
- impair the right to institute suit for the enforcement of any payment on the senior note;
- reduce the percentage in principal amount of outstanding senior notes the consent of whose holders is required for modification or amendment of the indenture or for waiver of compliance with certain provisions of the indenture or for waiver of defaults;
- reduce the quorum or voting requirements applicable to holders of the senior notes; or
- modify the provisions of the indenture with respect to modification and waiver, except as provided in the indenture.

We and the trustee may, without the consent of any holder of senior notes, modify and amend the indenture for certain purposes, including to:

- add covenants or other provisions applicable to us and for the benefit of the holders of senior notes or one or more specified series thereof or to surrender any right or power conferred on us;
- cure any ambiguity or to correct or supplement any provision of the indenture which may be defective or inconsistent with other provisions;
- make any other additions to, deletions from or changes to the provisions under the indenture so long as the additions, deletions or changes do not materially adversely affect the holders of any series of senior notes in any material respect;
- change or eliminate any provision of the indenture or add any new provision so long as the change, elimination or addition does not adversely affect the interests of holders of senior notes of any series in any material respect; and

- change any place or places for payment or surrender of senior notes and where notices and demands to us may be served.

The holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the indenture, voting as a single class, may waive compliance by us with our covenant in respect of our corporate existence and the covenants described under “Restrictions on Liens and Sale and Leaseback Transactions” and “Consolidation, Merger, Conveyance or Transfer” and with certain covenants and restrictions that may apply to a series of senior notes as provided in the indenture. The holders of not less than a majority in aggregate principal amount of the senior notes outstanding may, on behalf of the holders of all of the senior notes, waive any past default under the indenture and its consequences, except a default in the payment of the principal of or any premium or interest on any senior note and defaults in respect of a covenant or provision in the indenture which cannot be modified, amended or waived without the consent of each holder of affected senior notes.

In order to determine whether the holders of the requisite principal amount of the outstanding senior notes have taken an action under the indenture as of a specified date:

- the principal amount of a discount senior note that will be deemed to be outstanding will be the amount of the principal that would be due and payable as of that date upon acceleration of the maturity to that date; and

- senior notes owned by us or any other obligor upon the senior notes or any of our or their affiliates will be disregarded and deemed not to be outstanding.

**Events of Default**

An “event of default” means any of the following events which shall occur and be continuing:

- failure to pay interest on a senior note within 30 days after the interest becomes due and payable;

- failure to pay the principal of, or sinking fund payment or premium, if any, on, a senior note when due and payable;

- failure to perform or breach of any other covenant or warranty applicable to us in the indenture continuing for 90 days after the trustee gives us, or the holders of at least 33% in aggregate principal amount of the senior notes then outstanding give us and the trustee, written notice specifying the default or breach and requiring us to remedy the default or breach, unless the trustee or the trustee and holders of a principal amount of senior notes not less than the principal amount of senior notes the holders of which gave that notice agree in writing to an extension of the period prior to its expiration;

- certain events of bankruptcy, insolvency or reorganization; and

- the occurrence of any event of default as defined in any mortgage, indenture or instrument under which there may be issued, or by which there may be secured or evidenced, any of our debt, whether the debt existed on March 23, 2004 (the date senior notes were first issued under the original indenture), or is thereafter created, if the event of default: (i) is caused by a failure to pay principal after final maturity of the debt after the expiration of the grace period provided in the debt (which we refer to as a “payment default”) or (ii) results in the acceleration of the debt prior to its express maturity, and, in each case, the principal amount of the debt, together with the principal amount of any other debt under which there has been a payment default or the maturity of which has been so accelerated, aggregates $100 million or more.

The $100 million amount specified in the bullet point above shall be increased in any calendar year subsequent to 2004 by the same percentage increase in the urban CPI for the period commencing January 1, 2004

and ending on January 1 of the applicable calendar year. "Debt" for the purpose of the bullet point above means any debt of ours for money borrowed but, in each case, excluding liabilities in respect of capital lease obligations or swap agreements.

If the trustee deems it to be in the interest of the holders of the senior notes, it may withhold notice of default, except defaults in the payment of principal of or interest or premium on or with respect to, any senior note.

If an event of default occurs and is continuing, the trustee or the holders of not less than 33% in aggregate principal amount of the senior notes outstanding, considered as one class, may declare all principal due and payable immediately by notice in writing to us (and to the trustee if given by holders); provided, however, that if an event of default occurs with respect to the specified events of bankruptcy, insolvency or reorganization, then the senior notes outstanding shall be due and payable immediately without further action by the trustee or holders. If, after such a declaration of acceleration, we pay or deposit with the trustee all overdue interest and principal and premium on senior notes that would have been due otherwise, plus any interest and other conditions specified in the indenture have been satisfied before a judgment or decree for payment has been obtained by the trustee as provided in the indenture, the event or events of default giving rise to the acceleration will be deemed to have been waived and the declaration of acceleration and its consequences will be deemed to have been rescinded and annulled.

No holder of senior notes will have any right to enforce any remedy under the indenture unless the holder has given the trustee written notice of a continuing event of default, the holders of at least 33% in aggregate principal amount of the senior notes outstanding have requested the trustee in writing to institute proceedings in respect of the event of default in its own name as trustee under the indenture and the holder or holders have offered the trustee reasonable indemnity against costs, expenses and liabilities with respect to the request, the trustee has failed to institute any proceeding within 60 days after receiving the notice from holders, and no direction inconsistent with the written request has been given to the trustee during the 60-day period by holders of at least a majority in aggregate principal amount of senior notes then outstanding.

The trustee is not required to risk its funds or to incur financial liability if there is a reasonable ground for believing that repayment to it or adequate indemnity against risk or liability is not reasonably assured.

If an event of default has occurred and is continuing, holders of not less than a majority in principal amount of the senior notes then outstanding generally may direct the time, method and place of conducting any proceedings for any remedy available to the trustee, or exercising any trust or power conferred upon the trustee; provided the direction could not involve the trustee in personal liability where indemnity would not, in the trustee's sole discretion, be adequate.

**Satisfaction and Discharge**

Any senior note, or any portion of the principal amount thereof, will be deemed to have been paid for purposes of the indenture, and our entire indebtedness in respect of the senior notes will be deemed to have been satisfied and discharged, if certain conditions are satisfied, including an irrevocable deposit with the trustee or any paying agent (other than us) in trust of:

- money in an amount which will be sufficient; or
- in the case of a deposit made prior to the maturity of the senior notes or portions thereof, eligible obligations (as described below) which do not contain provisions permitting the redemption or other prepayment thereof at the option of the issuer thereof, the principal of and the interest on which when due, without any regard to reinvestment thereof, will provide monies which, together with the money, if any, deposited with or held by the trustee or the paying agent, will be sufficient; or
- a combination of either of the two items described in the two preceding bullet points which will be sufficient;

to pay when due the principal of and premium, if any, and interest, if any, due and to become due on the senior notes or portions thereof.

This discharge of the senior notes through the deposit with the trustee of cash or eligible obligations generally will be treated as a taxable disposition for U.S. federal income tax purposes by the holders of those senior notes. Prospective investors in the senior notes should consult their own tax advisors as to the particular U.S. federal income tax consequences applicable to them in the event of such discharge.

For this purpose, “eligible obligations” for U.S. dollar-denominated senior notes, means securities that are direct obligations of, or obligations unconditionally guaranteed by, the United States, entitled to the benefit of the full faith and credit thereof, or depositary receipts issued by a bank as custodian with respect to these obligations or any specific interest or principal payments due in respect thereof held by the custodian for the account of the holder of a depository receipt.

**Transfer and Exchange**

Senior notes of any series may be exchanged for other senior notes of the same series of authorized denominations and of like aggregate principal amount and tenor. Subject to the terms of the indenture and the limitations applicable to global securities, senior notes may be presented for exchange or registration of transfer at the office of the registrar without service charge (unless otherwise indicated in a prospectus supplement), upon payment of any taxes and other governmental charges imposed on registration of transfer or exchange. Such transfer or exchange will be effected upon the trustee, us or the registrar, as the case may be, being satisfied with the instruments of transfer.

If we provide for any redemption of a series of senior notes, we will not be required to execute, register the transfer of or exchange any senior note of that series for 15 days before a notice of redemption is mailed or register the transfer of or exchange any senior note selected for redemption.

**Global Securities**

Unless we indicate differently in a prospectus supplement, senior notes initially will be issued in book-entry form and represented by one or more global securities (collectively, the “global securities”), with an aggregate principal amount equal to that of the senior notes they represent. The global securities will be deposited with, or on behalf of, The Depositary Trust Company, New York, New York, as depositary (“DTC”), and registered in the name of Cede & Co., the nominee of DTC. Unless and until it is exchanged for individual certificates evidencing securities under the limited circumstances described below, a global security may not be transferred except as a whole by the depositary to its nominee or by the nominee to the depositary, or by the depositary or its nominee to a successor depositary or to a nominee of the successor depositary.

DTC has advised us that it is:

- a limited-purpose trust company organized under the New York Banking Law;
- a “banking organization” within the meaning of the New York Banking Law;
- a member of the Federal Reserve System;
- a “clearing corporation” within the meaning of the New York Uniform Commercial Code; and
- a “clearing agency” registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934.

DTC holds securities that its participants deposit with DTC. DTC also facilitates the settlement among its participants of securities transactions, including transfers and pledges, in deposited securities through electronic

computerized book-entry changes in participants' accounts, which eliminates the need for physical movement of securities certificates. "Direct participants" in DTC include securities brokers and dealers, including underwriters, banks, trust companies, clearing corporations and other organizations. DTC is a wholly owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC National Securities Clearance Corporation, all of which are registered clearing agencies, DTC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others, referred to as "indirect participants," that clear transactions through or maintain a custodial relationship with a direct participant either directly or indirectly. The rules applicable to DTC and its participants are on file with the SEC.

Purchases of securities within the DTC system must be made by or through direct participants, which will receive a credit for those securities on DTC's records. The ownership interest of the actual purchaser of a security, which we sometimes refer to as a "beneficial owner," is in turn recorded on the direct and indirect participants' records. Beneficial owners of securities will not receive written confirmation from DTC of their purchases. However, beneficial owners are expected to receive written confirmations providing details of their transactions, as well as periodic statements of their holdings, from the direct or indirect participants through which they purchased securities. Transfers of ownership interests in global securities are to be accomplished by entries made on the books of participants acting on behalf of beneficial owners. Beneficial owners will not receive certificates representing their ownership interests in the global securities except under the limited circumstances described below.

To facilitate subsequent transfers, all global securities deposited by direct participants with DTC will be registered in the name of DTC's partnership nominee, Cede & Co, or such other name as may be requested by an authorized representative of DTC. The deposit of securities with DTC and their registration in the name of Cede & Co. or such other nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual beneficial owners of the securities. DTC's records reflect only the identity of the direct participants to whose accounts the securities are credited, which may or may not be the beneficial owners. The direct and indirect participants are responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to direct participants, by direct participants to indirect participants and by direct participants and indirect participants to beneficial owners will be governed by arrangements among them, subject to any legal requirements in effect from time to time. Beneficial owners of securities may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the securities, such as redemptions, tenders, defaults, and proposed amendments to the security documents. For example, beneficial owners of securities may wish to ascertain that the nominee holding the securities for their benefit has agreed to obtain and transmit notices to beneficial owners. In the alternative, beneficial owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices will be sent to DTC or its nominee. If less than all of the securities of a particular series are being redeemed, DTC's practice is to determine by lot the amount of the interest of each direct participant in such issue to be redeemed.

In any case where a vote may be required with respect to securities of a particular series, neither DTC nor Cede & Co. (nor any other DTC nominee) will give consents for or vote the global securities, unless authorized by a direct participant in accordance with DTC's procedures. Under its usual procedures, DTC will mail an omnibus proxy to us as soon as possible after the record date. The omnibus proxy assigns the consenting or voting rights of Cede & Co. to those direct participants to whose accounts the securities of such series are credited on the record date identified in a listing attached to the omnibus proxy.

Principal and interest payments on the securities will be made to Cede & Co., as or such other nominee as may be requested by authorized representative of DTC. DTC's practice is to credit direct participants' accounts upon receipt of funds and corresponding detail information from us or the paying agent in accordance with their respective holdings shown on DTC's records. Payments by direct and indirect participants to beneficial owners will be governed by standing instructions and customary practices, as is the case with securities held for the

account of customers in bearer form or registered in "street name." Those payments will be the responsibility of participants and not of DTC, the paying agent or us, subject to any legal requirements in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may otherwise be requested by an authorized representative of DTC) is our responsibility, disbursement of payments to direct participants is the responsibility of DTC and disbursement of payments to the beneficial owners is the responsibility of direct and indirect participants.

Except under the limited circumstances described below, purchasers of securities will not be entitled to have securities registered in their names and will not receive physical delivery of securities. Accordingly, each beneficial owner must rely on the procedures of DTC and its participants to exercise any rights under the securities and the applicable indenture.

The laws of some jurisdictions may require that some purchasers of securities take physical delivery of securities in definitive form. Those laws may impair the ability to transfer or pledge beneficial interests in securities.

DTC may discontinue providing its services as securities depository with respect to the securities at any time by giving us reasonable notice. Under such circumstances, in the event that a successor securities depository is not obtained, certificates representing the securities are required to be printed and delivered. Also, we may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository), in which event, certificates representing the securities will be printed and delivered to DTC.

We have obtained the information in this section and elsewhere in this prospectus concerning DTC and DTC's book-entry system from sources that are believed to be reliable, but we take no responsibility for the accuracy of this information.

**Resignation or Removal of Trustee**

The trustee may resign at any time upon written notice to us and the trustee may be removed at any time by written notice delivered to the trustee and us and signed by the holders of at least a majority in principal amount of the outstanding senior notes. No resignation or removal of a trustee will take effect until a successor trustee accepts appointment. In addition, under certain circumstances, we may remove the trustee. We must give notice of resignation and removal of the trustee or the appointment of a successor trustee to all holders of senior notes as provided in the indenture.

**Trustees, Paying Agents and Registrars for the Senior Notes**

The Bank of New York Mellon Trust Company, N.A. acts as the trustee, paying agent and registrar under the indenture. We may change either the paying agent or registrar without prior notice to the holders of the senior notes, and we may act as paying agent. We and our affiliates maintain ordinary banking and trust relationships with a number of banks and trust companies, including The Bank of New York Mellon Trust Company, N.A.

**Governing Law**

The indenture and the senior notes are governed by California law.

## PLAN OF DISTRIBUTION

We may sell any series of senior notes being offered by this prospectus in one or more of the following ways from time to time:

- to underwriters or dealers for resale to the public or to institutional investors;
- directly to institutional investors; or
- through agents to the public or to institutional investors.

A prospectus supplement applicable to each series of senior notes will state the terms of the offering of the senior notes, including:

- the name or names of any underwriters or agents;
- the purchase price of the senior notes and the proceeds to be received by us from the sale;
- any underwriting discounts or agency fees and other items constituting underwriters' or agents' compensation;
- any initial public offering price;
- any discounts or concessions allowed or reallowed or paid to dealers; and
- any securities exchange or automated quotation system on which the senior notes may be listed.

If we use underwriters in the sale, the senior notes will be acquired by the underwriters for their own accounts and may be resold from time to time in one or more transactions, including:

- negotiated transactions;
- at a fixed public offering price or prices, which may be changed;
- at market prices prevailing at the time of sale;
- at prices based on prevailing market prices; or
- at negotiated prices.

Senior notes may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more of those firms. The specific managing underwriter or underwriters, if any, will be named in the prospectus supplement relating to the particular senior notes together with the members of the underwriting syndicate, if any. Unless otherwise set forth in a prospectus supplement, the obligations of the underwriters to purchase the particular senior notes will be subject to certain conditions precedent and the underwriters will be obligated to purchase all of the senior notes being offered if any are purchased.

We may sell senior notes directly or through agents we designate from time to time. The prospectus supplement will set forth the name of any agent involved in the offer or sale of senior notes in respect of which such prospectus supplement is delivered and any commissions payable by us to such agent. Unless otherwise indicated in a prospectus supplement, any agent will be acting on a best efforts basis for the period of its appointment.

Any underwriters, dealers or agents participating in the distribution of senior notes may be deemed to be underwriters as defined in the Securities Act, and any discounts or commissions received by them on the sale or resale of senior notes may be deemed to be underwriting discounts and commissions under the Securities Act. We may agree with the underwriters, dealers and agents to indemnify them against certain civil liabilities, including liabilities under the Securities Act or to contribute with respect to payments which the underwriters, dealers or agents may be required to make in respect of these liabilities.

Unless otherwise specified in a prospectus supplement, senior notes will not be listed on a securities exchange. Any underwriters to whom senior notes are sold by us for public offering and sale may make a market in the senior notes, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice.

To facilitate a senior notes offering, any underwriter may engage in over-allotment, short covering transactions and penalty bids or stabilizing transactions in accordance with Regulation M under the Securities Exchange Act of 1934.

- Over-allotment involves sales in excess of the offering size, which creates a short position.
- Stabilizing transactions permit bids to purchase the underlying senior notes so long as the stabilizing bids do not exceed a specified maximum.
- Short covering positions involve purchases of senior notes in the open market after the distribution is completed to cover short positions.
- Penalty bids permit the underwriters to reclaim a selling concession from a dealer when senior notes originally sold by the dealer are purchased in a covering transaction to cover short positions.

These activities may cause the price of the senior notes to be higher than it otherwise would be. If commenced, these activities may be discontinued by the underwriters at any time.

## EXPERTS

The consolidated financial statements and the related financial statement schedules, incorporated in this prospectus by reference from the Company's Annual Report on Form 10-K, and the effectiveness of Pacific Gas and Electric Company's internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports, which are incorporated herein by reference. Such financial statements and financial statement schedules have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

## LEGAL MATTERS

The validity of the senior notes has been passed upon for us by Orrick, Herrington & Sutcliffe LLP. The validity of the senior notes will be passed upon for any agents, dealers or underwriters by their counsel named in the applicable prospectus supplement.

## WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, information statements and other information with the SEC under File No. 001-2348. These SEC filings are available to the public over the Internet at the SEC's website at http://www.sec.gov. You may also read and copy any of these SEC filings at the SEC's public reference room at 100 F Street, N.E., Washington D.C. 20549.

## CERTAIN DOCUMENTS INCORPORATED BY REFERENCE

We have "incorporated by reference" into this prospectus certain information that we file with the SEC. This means that we can disclose important business, financial and other information in this prospectus by referring you to the documents containing this information.

We incorporate by reference the documents listed below and any future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 (other than information deemed to be furnished and not filed) before the termination of the offering of the senior notes offered hereby:

- our Annual Report on Form 10-K for the year ended December 31, 2013; and
- our Current Report on Form 8-K filed with the SEC on January 2, 2014.

The incorporation by reference of the filings listed above does not extend to any such filings made by Corp and not us or to any information in any filings jointly made by Corp and us regarding Corp or its other subsidiaries, but not regarding us.

All information incorporated by reference is deemed to be part of this prospectus except to the extent that the information is updated or superseded by information filed with the SEC after the date the incorporated information was filed (including later-dated reports listed above) or by the information contained in this prospectus or the applicable prospectus supplement. Any information that we subsequently file with the SEC that is incorporated by reference, as described above, will automatically update and supersede as of the date of such filing any previous information that had been part of this prospectus or the applicable prospectus supplement, or that had been incorporated herein by reference.

You may request a copy of these filings at no cost by writing or contacting us at the following address:

The Office of the Corporate Secretary
PG&E Corporation
77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
Telephone: (415) 973-8200
Facsimile: (415) 973-8719

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**$650,000,000**
**$250,000,000 Floating Rate Senior Notes due November 30, 2017**
**$400,000,000 4.00% Senior Notes due December 1, 2046**

**PROSPECTUS SUPPLEMENT**

**November 28, 2016**

*Joint Book-Running Managers*

**BofA Merrill Lynch**
**Citigroup**
**J.P. Morgan**
**Mizuho Securities**

*Co-Managers*

**CIBC Capital Markets**
**SMBC Nikko**
**US Bancorp**
**Lebenthal & Co., LLC**
**Mischler Financial Group, Inc.**
**Ramirez & Co., Inc.**

# Exhibit 21

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Filed Pursuant to Rule 424(b)(5)
Registration No. 333-215427

**This preliminary prospectus supplement and the accompanying prospectus relate to an effective registration statement under the Securities Act of 1933. The information in this preliminary prospectus supplement is not complete and may be subject to change. This preliminary prospectus supplement and the accompanying prospectus are not an offer to sell these securities and we are not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.**

**SUBJECT TO COMPLETION**
**PRELIMINARY PROSPECTUS SUPPLEMENT DATED MARCH 7, 2017**

**PROSPECTUS SUPPLEMENT**
**(To Prospectus dated January 25, 2017)**

Pacific Gas and Electric Company®

# $

# $ % Senior Notes due
# $ 4.00 % Senior Notes due December 1, 2046

We are offering $ principal amount of our % Senior Notes due , 20 , which we refer to in this prospectus supplement as our "20 notes" and an additional $ principal amount of our 4.00% Senior Notes due December 1, 2046, which we refer to in this prospectus supplement as our "2046 notes." The 20 notes and the 2046 notes are collectively referred to in this prospectus supplement as the "senior notes."

We will pay interest on our 20 notes offered hereby on each and , commencing , 2017. We will pay interest on our 2046 notes offered hereby on each June 1 and December 1, commencing June 1, 2017. The senior notes will be issued in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The terms of the 2046 notes, other than their issue date and public offering price, will be identical to the terms of the $400,000,000 principal amount of 4.00% Senior Notes due December 1, 2046 offered and sold by our prospectus supplement dated November 28, 2016 and the accompanying prospectus. The 2046 notes offered by this prospectus supplement and the accompanying prospectus will have the same CUSIP number as the other notes of the same series and will trade interchangeably with notes of the same series immediately upon settlement. Upon consummation of this offering, the aggregate principal amount of our 4.00% Senior Notes due December 1, 2046, including the 2046 notes offered hereby, will be $ .

We may redeem either series of the senior notes in whole or in part at any time at the respective redemption prices set forth in this prospectus supplement.

The senior notes will be unsecured and will rank equally with all of our other unsecured and unsubordinated indebtedness from time to time outstanding.

There is no existing public market for the senior notes. We do not intend to apply to list the senior notes on any securities exchange or any automated quotation system.

**Investing in these senior notes involves risks. See "Risk Factors" on page S-1 of this prospectus supplement.**

| | Per 20 Note | Total | Per 2046 Note | Total |
|---|---|---|---|---|
| Public Offering Price(1) | % | $ | % | $ |
| Underwriting Discounts and Commissions | % | $ | % | $ |
| Proceeds to Pacific Gas and Electric Company (before expenses)(1) | % | $ | % | $ |

(1) Plus accrued interest, (i) with respect to the 20 notes, from and including original issuance of the 20 notes, and (ii) with respect to the 2046 notes, from and including December 1, 2016 to but excluding the delivery date (totaling $ ). Accrued interest on the 2046 notes must be paid by the purchasers of the 2046 notes, and must be paid by the purchasers of the 20 notes in the event the 20 notes are delivered after March , 2017.

**None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus supplement or the accompanying prospectus. Any representation to the contrary is a criminal offense.**

The senior notes are expected to be delivered on or about , 2017 through the book-entry facilities of The Depository Trust Company for the accounts of its participants, including Clearstream Banking, *société anonyme*, and Euroclear Bank S.A./N.V.

*Joint Book-Running Managers*

**BNP PARIBAS** **Goldman, Sachs & Co.** **RBC Capital Markets** **Wells Fargo Securities**

*Co-Managers*

**BNY Mellon Capital Markets, LLC** **TD Securities** **Blaylock Beal Van, LLC** **MFR Securities, Inc.**

, 2017

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**This prospectus supplement should be read in conjunction with the accompanying prospectus. You should rely only on the information contained in this prospectus supplement, the accompanying prospectus, the information incorporated by reference into this prospectus supplement and the accompanying prospectus and any free writing prospectus prepared by us. Neither we nor any underwriter has authorized any other person to provide you with different or additional information. If anyone provides you with different or additional information, you should not rely on it. Neither we nor any underwriter is making an offer to sell the senior notes in any jurisdiction where the offer or sale is not permitted. You should assume that the information contained in or incorporated by reference in this prospectus supplement, the accompanying prospectus and any free writing prospectus prepared by us is accurate only as of the date of the document containing the information or such other date as may be specified therein.**

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Unless otherwise indicated, when used in this prospectus supplement and the accompanying prospectus, the terms “we,” “our,” “us” and “the Company” refer to Pacific Gas and Electric Company and its subsidiaries, and the term “Corp” refers to our parent, PG&E Corporation.

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## RISK FACTORS

Investing in the senior notes involves risk. These risks are described under "Risk Factors" in Item 1A of our annual report on Form 10-K for the fiscal year ended December 31, 2016, which is incorporated by reference in this prospectus supplement and the accompanying prospectus. See "Where You Can Find More Information" in the accompanying prospectus. Before making a decision to invest in the senior notes, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus.

## FORWARD-LOOKING STATEMENTS

This prospectus supplement, the accompanying prospectus and any documents incorporated by reference into this prospectus supplement and the accompanying prospectus contain forward-looking statements. These statements are subject to various risks and uncertainties, the realization or resolution of which may be outside of management's control. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this prospectus supplement.

These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that we will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the Butte fire litigation, and whether our insurance is sufficient to cover our liability resulting therefrom or whether insurance is otherwise available; and whether additional investigations and proceedings in connection with the Butte fire will be opened;
- the timing and outcomes of the 2017 general rate case, transmission owner rate case, cost of capital proceeding, and other ratemaking and regulatory proceedings;
- the terms of probation and the monitorship imposed in the sentencing phase of our federal criminal trial on January 26, 2017, the timing and outcomes of the debarment proceeding and potential remedial and other measures that could be imposed on us as a result of that proceeding, the Safety Enforcement Division of the California Public Utilities Commission's (SED) unresolved enforcement matters relating to our compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to our compliance with natural gas-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that we may incur in connection with the outcomes;
- the timing and outcomes of the California Public Utilities Commission's ("CPUC") investigation of communications between us and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, or of a potential settlement, and of the U.S. Attorney's Office in San Francisco and the California Attorney General's office investigations in connection with communications between our personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in our ratemaking proceedings;

- whether we are able to repair the harm to our reputation caused by our conviction in the federal criminal trial, the state and federal investigations of natural gas incidents, matters relating to the criminal federal trial, improper communications between the CPUC and us, and our ongoing work to remove encroachments from transmission pipeline rights-of-way;
- whether we can control our costs within the authorized levels of spending, and successfully implement a streamlined organizational structure and achieve project savings, the extent to which we incur unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;
- the timing and outcome of the complaint filed by the CPUC and certain other parties with the Federal Energy Regulatory Commission on February 2, 2017; the complaint requests we provide an open and transparent planning process for our capital transmission projects that do not go through the California Independent System Operator's Transmission Planning Process in order to allow for participation and input from interested parties. The planning process that may result from the outcome of the proceeding may impact the scope and timing of capital transmission projects that we will execute in the future;
- the outcome of the CPUC's investigation into our safety culture, and future legislative or regulatory actions that may be taken to require us to separate our electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;
- the outcomes of the SED's investigations of potential violations identified through audits, investigations, or self-reports including in connection with our February 2017 self-report related to our customer service representatives' drug and alcohol testing program;
- the outcome of future investigations or other enforcement proceedings that may be commenced relating to our compliance with laws, rules, regulations, or orders applicable to our operations, including the construction, expansion or replacement of our electric and gas facilities, inspection and maintenance practices, customer billing and privacy, and physical and cyber security, environmental laws and regulations;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge our known and unknown remediation obligations; and the extent to which we are able to recover environmental costs in rates or from other sources;
- the ultimate amount of unrecoverable environmental costs we incur associated with the our natural gas compressor station site located near Hinkley, California;
- the impact of maintenance costs of our electric transmission facilities;
- the impact of new legislation or Nuclear Regulatory Commission ("NRC") regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect our ability to continue operating Diablo Canyon nuclear power plant ("Diablo Canyon"); whether the CPUC approves the joint proposal that will phase out our Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether we obtain the approvals required to withdraw our NRC application to renew the two Diablo Canyon operating licenses; whether the State Lands Commission could be required to perform an environmental review of the new lands lease as a result of the World Business Academy's assertion that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act; and whether we will be able to successfully implement our retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;

- whether we are successful in ensuring physical security of our critical assets and whether our information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether we and our third party vendors and contractors (who host, maintain, modify and update some of our systems) are able to protect our operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether our security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether we can continue to rely on third-party vendors and contractors that maintain and support some of our information technology and operating systems;
- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt our service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by us, our customers, or third parties on which we rely; whether we incur liability to third parties for property damage or personal injury caused by such events; whether we are subject to civil, criminal, or regulatory penalties in connection with such events; and whether our insurance coverage is available for these types of claims and sufficient to cover our liability;
- how the CPUC and the California Air Resources Board ("CARB") implement state environmental laws relating to greenhouse gas, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether we are able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether we are able to timely recover our associated investment costs;
- the impact of the Senate Bill 887 directing Division of Oil, Gas and Geothermal Resources and CARB to develop permanent regulations for gas storage facility operations in California to comply with new safety and reliability measures, as well the impact of the Pipeline and Hazardous Materials Safety Administration rules effective January 18, 2017 regulating gas storage facilities at the federal level;
- whether our climate change adaptation strategies are successful;
- the impact that reductions in customer demand for electricity and natural gas have on our ability to make and recover our investments through rates and earn our authorized return on equity, and whether we are successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing for Community Choice Aggregators;
- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which we can manage and respond to the volatility of energy commodity prices; our ability and the ability of our counterparties to post or return collateral in connection with price risk management activities; and whether we are able to recover timely our electric generation and energy commodity costs through rates, including our renewable energy procurement costs;
- disruptions and delays in nuclear fuel supply and related services by our sole source of nuclear fuel assemblies Westinghouse Electric Company, LLC ("WEC"), delays in connection with the Diablo Canyon outage and refueling, and adverse changes in contracts with WEC, as a result of which we could incur additional costs and expenses that could be material and there is no assurance that they would be recoverable in rates;
- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether we can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- our ability to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;
- changes in credit ratings which could result in increased borrowing costs especially if we were to lose our investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the impact of the corporate tax reform considered by the new federal administration and the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;
- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the new federal administration; and
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and our future financial condition, results of operations and cash flows, you should read the sections titled "Risk Factors" in the documents incorporated by reference in this prospectus supplement and the accompanying prospectus.

You should read this prospectus supplement, the accompanying prospectus and the documents that we incorporate by reference into this prospectus supplement and the accompanying prospectus, the documents that we have included as exhibits to the registration statement of which this prospectus supplement and the accompanying prospectus are a part and the documents that we refer to under the section of the accompanying prospectus titled "Where You Can Find More Information" completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statements. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus supplement or the date of the document incorporated by reference. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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## OUR COMPANY

We are one of the largest combination natural gas and electric utilities in the United States. We were incorporated in California in 1905 and are a subsidiary of PG&E Corporation. We provide natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers. The principal executive offices of PG&E Corporation and Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and the telephone number of Pacific Gas and Electric Company is (415) 973-7000.

## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our historical ratio of earnings to fixed charges for each of the fiscal years indicated.

| 2016 | 2015 | 2014 | 2013 | 2012 |
|---|---|---|---|---|
| 2.04x | 1.67x | 2.55x | 2.23x | 2.24x |

For the purpose of computing our ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, allowance for funds used during construction debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

## USE OF PROCEEDS

We estimate that the net proceeds from this offering will be approximately $ million, after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We expect to use the net proceeds from the offering for general corporate purposes, including to repay our outstanding commercial paper. At March 6, 2017, the outstanding commercial paper was approximately $954 million, the weighted average yield on our outstanding commercial paper was approximately 0.91% per annum and the weighted average maturity on our outstanding commercial paper was approximately 14 days.

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## CAPITALIZATION

The following table sets forth our consolidated capitalization as of December 31, 2016, as adjusted to give effect to (i) the issuance and sale of the senior notes, and (ii) the use of net proceeds from this offering as set forth under "Use of Proceeds" in this prospectus supplement. This table should be read in conjunction with our consolidated financial statements and related notes as of and for the fiscal year ended December 31, 2016, incorporated by reference in this prospectus supplement and the accompanying prospectus. See "Where You Can Find More Information" in the accompanying prospectus.

| | As of December 31, 2016 | |
|---|---|---|
| | Actual | As Adjusted |
| | (in millions) | |
| Current Liabilities: | | |
| Short-term borrowings(1) | $ 1,516 | $ |
| Total long-term debt classified as current | $ 700 | $ |
| Capitalization: | | |
| Long-term debt(2) | $15,872 | $ |
| Shareholders' equity(3) | 18,395 | |
| Total capitalization | $34,267 | $ |

(1) Actual short-term borrowings primarily included commercial paper and a $250 million floating rate note and as adjusted short-term borrowings gives effect to the use of proceeds of this offering to repay a portion of our outstanding commercial paper.
(2) Actual long-term debt consisted of $1,108 million of pollution control bonds and $14,764 million of senior notes and as adjusted long-term debt includes the senior notes offered hereby, in each case, net of any discounts and premiums.
(3) Includes $258 million of preferred stock without mandatory redemption provisions.

## DESCRIPTION OF THE SENIOR NOTES

### General

You should read the following information in conjunction with the statements under "Description of the Senior Notes" in the accompanying prospectus.

As used in this section, the terms "we," "us" and "our" refer to Pacific Gas and Electric Company, and not to any of our subsidiaries.

The 20 notes are being offered in the aggregate principal amount of $ and will mature on , 20 .

The 2046 notes are being offered in the aggregate principal amount of $ and will mature on December 1, 2046.

We will issue the senior notes under an existing indenture, which was originally entered into on March 11, 2004 and amended and restated on April 22, 2005, between us and The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A.), as trustee, as supplemented by supplemental indentures between us and the trustee. Please read the indenture because it, and not this description, defines your rights as holders of the senior notes. We have filed with the Securities and Exchange Commission a copy of the indenture as an exhibit to the registration statement of which this prospectus supplement and the accompanying prospectus are a part.

Pursuant to the Trust Indenture Act of 1939, as amended, or the 1939 Act, if a default occurs on the senior notes, The Bank of New York Mellon Trust Company, N.A. may be required to resign as trustee under the indenture if it has a conflicting interest (as defined in the 1939 Act), unless the default is cured, duly waived or otherwise eliminated within 90 days.

The 2046 notes form a part of the series of our 4.00% Senior Notes due December 1, 2046 and will have the same terms as the other notes of this series other than their issue date and the public offering price at which the 2046 notes are sold by this prospectus supplement and the accompanying prospectus. We first issued our 4.00% Senior Notes due December 1, 2046 on December 1, 2016. The 2046 notes offered by this prospectus supplement and the accompanying prospectus will have the same CUSIP number as the other notes of the same series and will trade interchangeably with notes of the same series immediately upon settlement. Upon the consummation of this offering, the aggregate principal amount of our 4.00% Senior Notes due December 1, 2046, including the 2046 notes offered hereby, will be $ .

We may, without consent of the holders of senior notes, issue additional notes under the indenture, having the same terms in all respects to either series of senior notes (except for the public offering price and the issue date and, in some cases, the first interest payment date) so that those additional notes will be consolidated and form a single series with the other outstanding senior notes of such series.

The 20 notes will bear interest from , 2017 at % per annum, payable semiannually on each and , commencing on , 2017 to holders of record at the close of business on and immediately preceding the interest payment date.

The 2046 notes offered hereby will bear interest from December 1, 2016 at 4.00% per annum, payable semiannually on each June 1 and December 1, commencing on June 1, 2017, to holders of record on May 15 and November 15 immediately preceding the interest payment date.

We will issue the senior notes in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

Each series of senior notes will be redeemable at our option, in whole or in part, at any time as described below under "Optional Redemption for Senior Notes – Optional Redemption for 20 Notes" and "Optional Redemption for Senior Notes – Optional Redemption for 2046 Notes."

Interest on the senior notes will be computed on the basis of a 360-day year consisting of twelve 30-day months. If any payment date falls on a day that is not a business day, the payment will be made on the next business day, but we will consider that payment as being made on the date that the payment was due to you. In that event, no interest will accrue on the amount payable for the period from and after such payment date to such next business day.

We will issue the senior notes in the form of one or more global securities, which will be deposited with, or on behalf of, The Depository Trust Company, or DTC, and registered in the name of DTC's nominee. Information regarding DTC's book-entry system is set forth below under "Book-Entry System; Global Notes."

**Ranking**

The senior notes will be our direct, unsecured and unsubordinated obligations and will rank equally with all our other existing and future unsecured and unsubordinated obligations. The senior notes will be effectively subordinated to all our secured debt. As of December 31, 2016, we had approximately $15.9 billion of notes outstanding under the indenture for senior notes. The indenture contains no restrictions on the amount of additional indebtedness that may be incurred by us.

As of December 31, 2016, we did not have any outstanding secured debt for borrowed money.

**Optional Redemption for Senior Notes**

***Optional Redemption for 20 Notes***

At any time prior to (the date that is months prior to the maturity date), we may, at our option, redeem the 20 notes in whole or in part at a redemption price equal to the greater of:

- 100% of the principal amount of the 20 notes to be redeemed; or
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 20 notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) calculated as if the maturity date of the 20 notes was (the date that is months prior to the maturity date), discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate plus basis points,

plus, in either case, accrued and unpaid interest to, but not including, the redemption date.

At any time on or after (the date that is months prior to the maturity date), we may redeem the 20 notes, in whole or in part, at 100% of the principal amount of the 20 notes being redeemed plus accrued and unpaid interest to, but not including, the redemption date.

As used in this section "Optional Redemption for 20 Notes," the following terms shall have the following meanings:

"Adjusted Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date.

"Business Day" means any day that is not a day on which banking institutions in New York City are authorized or required by law or regulation to close.

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"Comparable Treasury Issue" means the United States Treasury security selected by the applicable Quotation Agent as having a maturity comparable to the remaining term of the 20 notes to be redeemed, assuming, for such purpose, that the 20 notes matured on , 20 (the date that is months prior to the maturity date (the "remaining term")), that would be used, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the 20 notes to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date:

- the average of the Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest of the Reference Treasury Dealer Quotations; or
- if we obtain fewer than four Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations so received.

"Quotation Agent" means the Reference Treasury Dealer appointed by us for the 20 notes.

"Reference Treasury Dealer" means (1) each of BNP Paribas Securities Corp., Goldman, Sachs & Co., RBC Capital Markets, LLC and Wells Fargo Securities, LLC and their respective successors, unless any of them ceases to be a primary dealer in certain U.S. government securities ("Primary Treasury Dealer"), in which case we shall substitute another Primary Treasury Dealer; and (2) any other Primary Treasury Dealer selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that redemption date.

***Optional Redemption for 2046 Notes***

At any time prior to June 1, 2046 (the date that is six months prior to the maturity date), we may, at our option, redeem the 2046 notes in whole or in part at a redemption price equal to the greater of:

- 100% of the principal amount of the 2046 notes to be redeemed; or
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2046 notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) calculated as if the maturity date of the 2046 notes was June 1, 2046 (the date that is six months prior to the maturity date), discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate plus 20 basis points,

plus, in either case, accrued and unpaid interest to, but not including, the redemption date.

At any time on or after June 1, 2046 (the date that is six months prior to the maturity date), we may redeem the 2046 notes, in whole or in part, at 100% of the principal amount of the 2046 notes being redeemed plus accrued and unpaid interest to, but not including, the redemption date.

As used in this section "Optional Redemption for 2046 Notes," the following terms shall have the following meanings:

"Adjusted Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date.

"Business Day" means any day that is not a day on which banking institutions in New York City are authorized or required by law or regulation to close.

"Comparable Treasury Issue" means the United States Treasury security selected by the applicable Quotation Agent as having a maturity comparable to the remaining term of the 2046 notes to be redeemed, assuming, for such purpose, that the 2046 notes matured on June 1, 2046 (the date that is six months prior to the maturity date (the "remaining term")), that would be used, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the 2046 notes to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date:

- the average of the Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest of the Reference Treasury Dealer Quotations; or
- if we obtain fewer than four Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations so received.

"Quotation Agent" means the Reference Treasury Dealer appointed by us for the 2046 notes.

"Reference Treasury Dealer" means (1) each of Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA Inc. and their respective successors, unless any of them ceases to be a primary dealer in certain U.S. government securities ("Primary Treasury Dealer"), in which case we shall substitute another Primary Treasury Dealer; and (2) any other Primary Treasury Dealer selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that redemption date.

***General Senior Note Optional Redemption Terms***

The redemption price of the senior notes will be calculated assuming a 360-day year consisting of twelve 30-day months.

We will send notice of any redemption of the senior notes at least 10 days but not more than 60 days before the redemption date to each registered holder of the senior notes to be redeemed.

Unless we default in payment of the redemption price of the senior notes, on and after the redemption date, interest will cease to accrue on the senior notes or portions of the senior notes called for redemption.

If we redeem only some of the senior notes, DTC's practice is to choose by lot the amount to be redeemed from the senior notes held by each of its participating institutions. DTC will give notice to these participants, and these participants will give notice to any "street name" holders of any indirect interests in the senior notes to be redeemed according to arrangements among them. These notices may be subject to statutory or regulatory requirements. We will not be responsible for giving notice of a redemption of the senior notes to be redeemed to anyone other than the registered holders of the senior notes to be redeemed, which is currently DTC. If senior notes to be redeemed are no longer held through DTC and fewer than all the senior notes are to be redeemed, selection of senior notes for redemption will be made by the trustee in any manner the trustee deems fair and appropriate.

Subject to the foregoing and to applicable law (including, without limitation, United States federal securities laws), we or our affiliates may, at any time and from time to time, purchase outstanding senior notes by tender, in the open market or by private agreement.

### No Sinking Fund for Senior Notes

There is no provision for a sinking fund for the senior notes.

### Covenants

The indenture restricts us and any of our subsidiaries which are "significant subsidiaries" from incurring or assuming secured debt or entering into sale and leaseback transactions, except in certain circumstances. The accompanying prospectus describes this covenant (see "Description of the Senior Notes—Restrictions on Liens and Sale and Leaseback Transactions" in the accompanying prospectus) and other covenants contained in the indenture in greater detail and should be read prior to investing.

### Book-Entry System; Global Notes

Each series of senior notes will initially be issued in the form of one or more global notes. Each series of senior notes will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered security certificate will be issued for each series of senior notes in the aggregate principal amount of such series of senior notes, and will be deposited with DTC or the trustee on behalf of DTC and registered in the name of DTC or its nominee. If, however, the aggregate principal amount of a series exceeds $500 million, one certificate will be issued with respect to each $500 million of principal amount of such series and an additional certificate will be issued with respect to any remaining principal amount of such series. Investors may hold their beneficial interests in a global note directly through DTC or indirectly through organizations which are participants in the DTC system.

## CERTAIN UNITED STATES FEDERAL INCOME TAX CONSEQUENCES

The following summary describes certain United States federal income tax consequences of the acquisition, ownership and disposition of the senior notes as of the date hereof. This summary is based on the Internal Revenue Code of 1986, as amended, as well as final, temporary and proposed Treasury regulations and administrative and judicial decisions. Legislative, judicial and administrative changes may occur, possibly with retroactive effect, that could affect the accuracy of the statements described herein. This summary generally is addressed only to original purchasers of the senior notes that purchase the senior notes at the initial offering price, deals only with senior notes held as capital assets and does not purport to address all United States federal income tax matters that may be relevant to investors in special tax situations, such as insurance companies, tax-exempt organizations, financial institutions, dealers in securities or currencies, traders in securities that elect to mark to market, holders of senior notes that are held as a hedge or as part of a hedging, straddle or conversion transaction, certain former citizens or residents of the United States, or United States holders (as defined below) whose functional currency is not the United States dollar. **Persons considering the purchase of the senior notes should consult their own tax advisors concerning the application of United States federal income tax laws, as well as the laws of any state, local or foreign taxing jurisdictions, to their particular situations.**

If a partnership (including an entity treated as a partnership for United States federal income tax purposes) is a beneficial owner of a senior note, the treatment of such partnership, or a partner in the partnership, will generally depend upon the status of the partner and upon the activities of the partnership. A beneficial owner of a senior note that is a partnership, and partners in such a partnership, should consult their tax advisors about the United States federal income tax consequences of holding and disposing of the senior notes.

We intend to treat the 2046 notes as being issued in a "qualified reopening" for United States federal income tax purposes. Consequently, we intend to treat the 2046 notes as part of the same issue for United States federal income tax purposes as the 4.00% Senior Notes due December 1, 2046. The aggregate price paid for the 2046 notes will include pre-issuance accrued interest from and including December 1, 2016. Such pre-issuance accrued interest will be included in the first interest payment that will be made on June 1, 2017 to the holders of the 2046 notes. We will exclude the pre-issuance accrued interest in determining the issue price of the 2046 notes and, in accordance with this treatment, holders of the 2046 notes will be required to treat a corresponding portion of the interest payable on the first interest payment date as a non-taxable return of the excluded pre-issuance accrued interest, rather than as an amount payable on the 2046 notes.

There are certain tax reform proposals currently being considered in connection with the recent United States elections. While it is uncertain whether any such proposals would be enacted into law, and it is impossible to predict whether this will be the case, if any such proposals were to become law, they could materially change the United States federal income tax consequences described below.

### United States Holders

This section describes the tax consequences to a United States holder. A "United States holder" is a beneficial owner of a senior note that is (i) a citizen or resident of the United States, (ii) a corporation (including an entity treated as a corporation for United States federal income tax purposes) created or organized in the United States or any state (including the District of Columbia), (iii) an estate whose income is subject to United States federal income tax on a net income basis in respect of the senior note, or (iv) a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorized to control all substantial decisions of the trust (or certain trusts that have made a valid election to be treated as a United States person).

If you are not a United States holder, this section does not apply to you. See "Non-United States Holders" below.

***Payment of Interest***

The senior notes will not be issued with more than a *de minimis* amount of original issue discount for United States federal income tax purposes. Interest on a senior note will therefore be taxable to a United States holder as ordinary interest income at the time it accrues or is received, in accordance with the United States holder's method of accounting for United States federal income tax purposes.

***Sale, Exchange or Retirement of Senior Notes***

Upon the sale, exchange, retirement or other taxable disposition of a senior note, a United States holder will recognize taxable gain or loss equal to the difference between the amount realized from the sale, exchange, retirement or other taxable disposition (other than amounts attributable to accrued interest not previously included in income, which will be taxable as ordinary interest income) and the United States holder's adjusted tax basis in the senior note. A United States holder's adjusted tax basis in a senior note will generally equal the cost of the senior note to such holder increased by the amount of any accrued but unpaid interest previously included in income. Such gain or loss generally will be capital gain or loss, and will be long-term capital gain or loss if the senior note has been held for more than one year. Capital losses are subject to certain limitations.

***Amortizable Bond Premium***

A United States holder who acquires a 2046 note for an amount that is greater than the stated principal amount (in excess of pre-issuance accrued interest) on the 2046 note will be considered to have purchased such note at a premium. A United States holder generally may elect to amortize such premium using a constant yield method over the remaining term of the 2046 note as an offset to interest when includible in income under the United States holder's method of accounting for tax purposes. Any such election shall apply to all debt instruments (other than debt instruments the interest on which is excludable from gross income) held at the beginning of the first taxable year to which the election applies or thereafter acquired, and is irrevocable without the consent of the Internal Revenue Service. However, because the 2046 notes may be redeemed by us under certain circumstances for a price equal to or greater than the principal amount prior to their maturity date, special rules may affect the amount and timing of the deduction. A United States holder that acquires a 2046 note for an amount that is greater than the stated principal amount (in excess of pre-issuance accrued interest) on the 2046 note should consult with their own tax advisor regarding the consequences of making the amortizable bond premium election and the availability of other elections for United States federal income tax purposes.

***Tax on Net Investment Income***

Certain non-corporate United States holders of senior notes generally will be subject to a 3.8% tax on their net investment income for the relevant taxable year. Subject to certain exceptions, a United States holder's calculation of its net investment income generally will include its interest income on, and its net gains from the disposition of, the senior notes. A United States holder that is an individual, estate or trust is urged to consult its tax advisor regarding the applicability of this tax to its income and gains in respect of your investment in the senior notes.

**Non-United States Holders**

This section describes the tax consequences to a non-United States holder. You are a "non-United States holder" if you are the beneficial owner of a senior note (other than a partnership, including an entity treated as a partnership for United States federal income tax purposes) and are not a United States holder for United States federal income tax purposes.

***Payment of Interest***

A non-United States holder generally will not be subject to United States federal withholding tax with respect to payments of principal and interest on the senior notes, provided that (i) the non-United States holder

does not actually or constructively own 10 percent or more of the total combined voting power of all classes of our stock entitled to vote, (ii) the non-United States holder is not for United States federal income tax purposes a controlled foreign corporation related to us (directly or indirectly) through stock ownership, and (iii) the beneficial owner of the senior notes certifies to us or the fiscal and paying agent (on Internal Revenue Service Form W-8BEN, Form W-8BEN-E or other applicable form) under penalties of perjury as to its status as a non-United States holder and complies with applicable identification procedures. Special rules apply to partnerships, estates and trusts and, in certain circumstances, certifications as to foreign status and other matters may be required to be provided by partners and beneficiaries thereof.

***Sale, Exchange or Retirement of Senior Notes***

A non-United States holder of a senior note generally will not be subject to United States federal income tax on any gain realized upon the sale, exchange, retirement or other disposition of a senior note, unless the non-United States holder is an individual who is present in the United States for 183 days or more during the taxable year of sale, retirement or other disposition and certain other conditions are met. In such case, the non-United States holder generally will be subject to a 30 percent tax on any capital gain recognized on the disposition of the senior notes, after being offset by certain United States source capital losses.

***United States Trade or Business***

If a non-United States holder of a senior note is engaged in a trade or business in the United States and income or gain from the senior note is effectively connected with the conduct of such trade or business, the non-United States holder will be exempt from withholding tax if appropriate certification has been provided, but will generally be subject to regular United States federal income tax on such income and gain in the same manner as if it were a United States holder. In addition, if such non-United States holder is a foreign corporation, it may be subject to a branch profits tax equal to 30 percent (or lower applicable treaty rate) of its effectively connected earnings and profits for the taxable year, subject to adjustments.

***Foreign Account Tax Compliance Act***

Sections 1471 through 1474 of the United States Internal Revenue Code, the Foreign Account Tax Compliance Act or FATCA provisions, impose a 30 percent United States withholding tax on certain types of payments made to certain foreign entities. Failure to comply with the additional certification, information reporting and other specified requirements imposed under FATCA could result in United States withholding tax being imposed on payments of interest and principal under the senior notes and sales proceeds of the senior notes held by or through a foreign entity. United States Treasury Regulations and applicable guidance provide that FATCA withholding generally applies to payments of interest, and will apply to (i) gross proceeds from the sale, exchange or retirement of debt obligations paid after December 31, 2018, and (ii) certain pass-thru payments received with respect to debt obligations held through foreign financial institutions beginning on the later of January 1, 2019 and the date that applicable final regulations are issued. Prospective investors should consult their own tax advisors regarding FATCA and its effect on them.

**Backup Withholding and Information Reporting**

In general, payments of interest and the proceeds of sale, exchange, retirement or other disposition of the senior notes payable by a United States paying agent or other United States intermediary will be subject to information reporting. With respect to a non-United States holder, we must report annually to the Internal Revenue Service and to each non-United States holder the amount of any interest paid to such holder regardless of whether any tax was actually withheld. Copies of the information returns reporting such interest payments to a non-United States holder and the amount of any tax withheld also may be made available to the tax authorities in the country in which the non-United States holder resides under the provisions of an applicable income tax treaty. In addition, backup withholding at the then applicable rate (currently 28 percent) will generally apply to these payments if:

- in the case of a United States holder, the holder fails to provide an accurate taxpayer identification number, fails to certify that the holder is not subject to backup withholding or fails to report all interest and dividends required to be shown on its United States federal income tax returns; or
- in the case of a non-United States holder, the holder fails to provide the certification on Internal Revenue Service Form W-8BEN, Form W-8BEN-E or other applicable form or otherwise does not provide evidence of exempt status.

Certain United States holders (including, among others, corporations) are not subject to information reporting or backup withholding. Any amount paid as backup withholding will be creditable against the holder's United States federal income tax liability and may entitle the holder to a refund, provided that the required information is timely furnished to the Internal Revenue Service. Holders of the senior notes should consult their tax advisors as to their qualification for exemption from backup withholding and the procedure for obtaining such an exemption.

## UNDERWRITING

Subject to the terms and conditions set forth in an underwriting agreement between us and the underwriters named below, for whom BNP Paribas Securities Corp., Goldman, Sachs & Co., RBC Capital Markets, LLC and Wells Fargo Securities, LLC are acting as representatives, we have agreed to sell to each of the underwriters, and each of the underwriters has severally and not jointly agreed to purchase from us, the principal amount of senior notes set forth opposite its name below.

| Underwriter | Principal Amount of 20 Notes | Principal Amount of 2046 Notes |
|---|---|---|
| BNP Paribas Securities Corp. | $ | $ |
| Goldman, Sachs & Co. | | |
| RBC Capital Markets, LLC | | |
| Wells Fargo Securities, LLC | | |
| BNY Mellon Capital Markets, LLC | | |
| TD Securities (USA) LLC | | |
| Blaylock Beal Van, LLC | | |
| MFR Securities, Inc. | | |
| Total | $ | |

The underwriters have agreed, subject to the terms and conditions set forth in the underwriting agreement, to purchase all of the senior notes if any of the senior notes are purchased.

The underwriters propose to offer the senior notes directly to the public at the public offering price specified on the cover page to this prospectus supplement and may also offer the senior notes to certain dealers at the public offering price less a concession not to exceed % of the principal amount of the 20 notes and % of the principal amount of the 2046 notes. The underwriters may allow, and these dealers may reallow, concession to certain brokers and dealers not to exceed % of the principal amount of the 20 notes and % of the principal amount of the 2046 notes. After the initial offering of the senior notes, the underwriters may change the offering price and concession.

There is no existing public market for the senior notes. We currently have no intention to apply to list the senior notes on any securities exchange or automated dealer quotation system. The underwriters may make a market in the senior notes after completion of the offering, but will not be obligated to make a market in the senior notes and may discontinue such market making at any time without notice. No assurance can be given as to the liquidity of the trading market for the senior notes or that an active public market for the senior notes will develop. If an active public trading market for the senior notes does not develop, the market price and liquidity of the senior notes may be adversely affected.

We will agree to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or to contribute to payments which the underwriters may be required to make in respect thereof.

We estimate our expenses for this offering, other than the underwriting discounts and commissions, to be approximately $ .

We will agree with the underwriters not to, during the period beginning from the date of the underwriting agreement through the closing of this offering, sell, offer to sell, grant any option for the sale of, or otherwise dispose of any debt securities other than the senior notes, without the prior written consent of each of BNP Paribas Securities Corp., Goldman, Sachs & Co., RBC Capital Markets, LLC and Wells Fargo Securities, LLC. This agreement will not apply to issuances of commercial paper or other debt securities with scheduled maturities of less than one year and the sale or remarketing of tax-exempt bonds issued by a governmental authority or body for our benefit.

In order to facilitate the offering, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the senior notes. Specifically, the underwriters may over-allot in connection with the offering, creating short positions in the senior notes for their own accounts. In addition, to cover over-allotments or to stabilize the price of the senior notes, the underwriters may bid for, and purchase, senior notes in the open market. The underwriters may reclaim selling concessions allowed to an underwriter or dealer for distributing senior notes in the offering if the underwriters repurchase previously distributed senior notes in transactions to cover short positions, in stabilization transactions or otherwise. Any of these activities may stabilize or maintain the market price of the senior notes above independent market levels. The underwriters are not required to engage in these activities and may end any of these activities at any time without notice.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased notes sold by or for the account of such underwriter in stabilizing or short covering transactions.

In general, purchases of a security for the purpose of stabilization or to reduce a short position could cause the price of the security to be higher than it might be in the absence of such purchases. The imposition of a penalty bid might also have an effect on the price of a security to the extent that it were to discourage resales of the security.

Neither we nor any underwriter makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the senior notes. In addition, neither we nor any underwriter makes any representation that the underwriters will engage in such transactions or that such transactions once commenced will not be discontinued without notice.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their affiliates have engaged and may in the future engage in transactions with, and, from time to time, have performed and may perform investment banking, corporate trust and/or commercial banking services for, us and certain of our affiliates in the ordinary course of business, for which they have received and will receive customary compensation. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments including serving as counterparties to certain derivative and hedging arrangements and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. Certain of the underwriters or their respective affiliates that have a lending relationship with us routinely hedge, and certain other of those underwriters or their respective affiliates may hedge, their credit exposure to us consistent with their customary risk management policies. Typically, these underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the notes offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the notes offered hereby. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments. Affiliates of one or more of the underwriters are part of a consortium of banks that participates in our revolving credit facility or Corp's revolving credit facility and may also hold our debt securities.

**Selling Restrictions**

***Notice to Prospective Investors in the European Economic Area***

In relation to each Member State of the European Economic Area ("EEA"), with effect from and including the date on which the Prospectus Directive is implemented in that Member State (the "Relevant Implementation Date"), an offer to the public of the notes may not be made in that Member State, except that an offer to the

public in that Member State of any notes may be made at any time with effect from and including the Relevant Implementation Date under the following exemptions under the Prospectus Directive:

(a) to any legal entity which is a qualified investor as defined in the Prospectus Directive;

(b) to fewer than 150 natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted by the Prospectus Directive, subject to obtaining the prior consent of the representatives of the underwriters for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of senior notes shall require the issuer or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of senior notes to the public" in relation to any senior notes in any Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the senior notes to be offered so as to enable an investor to decide to purchase or subscribe the senior notes, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State, the expression "Prospectus Directive" means Directive 2003/71/EC (as amended, including by Directive 2010/73/EU), and includes any relevant implementing measure in each Member State.

This European Economic Area selling restriction is in addition to any other selling restriction set out in this prospectus supplement and accompanying prospectus.

***Notice to Prospective Investors in the United Kingdom***

This communication is only being distributed to and is only directed at (i) persons who are outside the United Kingdom or (ii) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order") or (iii) high net worth companies, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as "relevant persons"). The senior notes are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such senior notes will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this prospectus supplement or the accompanying prospectus or any of their contents.

Each underwriter has represented, warranted and agreed that:

1.1 it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000 (the "FSMA")) received by it in connection with the issue or sale of the senior notes in circumstances in which Section 21(1) of the FSMA does not apply to the issuer; and

1.2 it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the senior notes in, from or otherwise involving the United Kingdom.

***Notice to Prospective Investors in Switzerland***

The senior notes may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("SIX") or on any other stock exchange or regulated trading facility in Switzerland. This prospectus supplement does not constitute a prospectus within the meaning of, and has been prepared without regard to the disclosure standards for issuance prospectuses under art. 652a or art. 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under art. 27 ff. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither this prospectus supplement nor any other offering or marketing material relating to the senior notes or the offering may be publicly distributed or otherwise made publicly available in Switzerland.

Neither this prospectus supplement nor any other offering or marketing material relating to the offering, the Company or the senior notes have been or will be filed with or approved by any Swiss regulatory authority. In particular, this prospectus supplement will not be filed with, and the offer of senior notes will not be supervised by, the Swiss Financial Market Supervisory Authority ("FINMA"), and the offer of senior notes has not been and will not be authorized under the Swiss Federal Act on Collective Investment Schemes ("CISA"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of the senior notes.

***Notice to Residents of Canada***

The senior notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the senior notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus supplement (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

***Notice to Prospective Investors in Hong Kong***

The senior notes may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the senior notes may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to senior notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

***Notice to Prospective Investors in Singapore***

This prospectus supplement has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus supplement and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the senior notes may not be circulated or distributed, nor may the senior notes be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the senior notes are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the senior notes under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

***Notice to Prospective Investors in Japan***

The senior notes have not been and will not be registered under the Financial Instruments and Exchange Act. Accordingly, the senior notes may not be sold or offered, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Act and any other applicable laws, regulations and ministerial guidelines of Japan.

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## GENERAL INFORMATION

The notes have been accepted for clearance through DTC and have been assigned the following identification number:

| | CUSIP Number | ISIN |
|---|---|---|
| 20 notes | | |
| 2046 notes | 694308HR1 | US694308HR19 |

## LEGAL MATTERS

The validity of the senior notes will be passed upon for us by Orrick, Herrington & Sutcliffe LLP, San Francisco, California. Skadden, Arps, Slate, Meagher & Flom LLP, New York, New York represents the underwriters. Skadden, Arps, Slate, Meagher & Flom LLP has in the past performed legal services in connection with federal regulatory matters for us and our affiliates.

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**PROSPECTUS**

# Pacific Gas and Electric Company

## $2,500,000,000

## Senior Notes

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We may offer and sell from time to time senior notes in one or more offerings. This prospectus provides you with a general description of the senior notes that may be offered.

Each time we offer and sell senior notes, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior notes. The prospectus supplement also may add, update or change information contained in this prospectus. You should carefully read this prospectus and any applicable prospectus supplement for the specific offering before you invest in any of the senior notes. This prospectus may not be used to sell senior notes unless accompanied by a prospectus supplement.

The senior notes may be sold to or through underwriters, dealers or agents or directly to other purchasers. A prospectus supplement will set forth the names of any underwriters, dealers or agents involved in the sale of the senior notes, the aggregate principal amount of senior notes to be purchased by them and the compensation they will receive.

**See "Risk Factors" on page 1 for information on certain risks related to the purchase of our securities.**

**None of the Securities and Exchange Commission, any state securities commission or any other regulatory body has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.**

January 25, 2017

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## ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or the SEC, using a shelf registration process. Under this shelf registration process, we may from time to time offer and sell senior notes in one or more offerings up to a total dollar amount of $2,500,000,000 as described in this prospectus.

This prospectus provides you with only a general description of the senior notes that we may offer. This prospectus does not contain all of the information set forth in the registration statement of which this prospectus is a part, as permitted by the rules and regulations of the SEC. For additional information regarding us and the offered senior notes, please refer to the registration statement of which this prospectus is a part. Each time we sell senior notes, we will provide a prospectus supplement that contains specific information about the offering and the terms of the offered senior notes. The prospectus supplement also may add, delete, update or change information contained in this prospectus. You should rely only on the information in the applicable prospectus supplement if this prospectus and the applicable prospectus supplement are inconsistent. Before purchasing any senior notes, you should carefully read both this prospectus and the applicable prospectus supplement, together with the additional information described under the section of this prospectus titled "Where You Can Find More Information." In particular, you should carefully consider the risks and uncertainties described under the section titled "Risk Factors" or otherwise included in any applicable prospectus supplement or incorporated by reference in this prospectus before you decide whether to purchase the senior notes. These risks and uncertainties, together with those not known to us or those that we may deem immaterial, could impair our business and ultimately affect our ability to make payments on the senior notes.

You should rely only on the information contained or incorporated by reference in this prospectus and in any applicable prospectus supplement. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. Neither we nor any underwriter, dealer or agent will make an offer to sell the senior notes in any jurisdiction where the offer or sale is not permitted. You should assume that the information in this prospectus and any applicable prospectus supplement is accurate only as of the dates on their covers and that any information incorporated by reference is accurate only as of the date of the document incorporated by reference, unless we indicate otherwise. Our business, financial condition, results of operations and prospects may have changed since those dates.

## PACIFIC GAS AND ELECTRIC COMPANY

We are a public utility serving more than 16 million people throughout 70,000 square miles in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers.

We were incorporated in California in 1905. Our principal executive offices are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and our telephone number at that location is (415) 973-7000.

When used in this prospectus, the terms "we," "our," "ours" and "us" refer to Pacific Gas and Electric Company, and the term "Corp" refers to our parent, PG&E Corporation, unless the context indicates that the references are to PG&E Corporation and its consolidated subsidiaries.

## RISK FACTORS

Investing in our securities involves risk. Please see risk factors described in our Annual Report on Form 10-K and other reports filed with the SEC, which are all incorporated by reference in this prospectus. Before making an investment decision, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus or the applicable supplement to this prospectus. The risks and uncertainties described are not the only ones facing us. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations, financial results and the value of our securities.

## FORWARD-LOOKING STATEMENTS

This prospectus, the documents incorporated by reference in this prospectus and any applicable prospectus supplement contain forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts as of the date of this prospectus. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline related expenses that we will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those related to environmental assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the 2017 general rate case and the transmission owner rate cases currently before the California Public Utilities Commission ("CPUC"), and other ratemaking and regulatory proceedings;

- the timing and outcomes of the debarment proceeding and potential remedial and other measures that may be imposed on us as a result of the debarment proceeding and the jury's verdict in the federal criminal trial (including a potential appointment of one or more independent third-party monitor(s)), the Safety and Enforcement Division's ("SED") unresolved enforcement matters relating to our compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to our compliance with natural gas-related laws and regulations, including the U.S. Attorney's Office investigation in connection with the natural gas explosion that occurred in

Carmel, California on March 3, 2014 and the U.S. Attorney's Office in San Francisco investigation in connection with matters relating to the federal criminal trial, and the ultimate amount of fines, penalties, and remedial costs that we may incur in connection with the outcomes;

- the timing and outcomes of the CPUC's investigation of communications between us and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, and of the U.S. Attorney's Office in San Francisco and the California Attorney General's office investigations in connection with communications between our personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in our ratemaking proceedings;

- the timing and outcomes of the Butte fire litigation, and whether our insurance is sufficient to cover our liability resulting therefrom or whether insurance is otherwise available; and whether additional investigations and proceedings in connection with the Butte fire will be opened;

- whether Corp and we are able to repair the harm to our reputations caused by the jury's verdict in the federal criminal trial and our possible conviction, the state and federal investigations of natural gas incidents, matters relating to the criminal federal trial, improper communications between the CPUC and us, and our ongoing work to remove encroachments from transmission pipeline rights-of-way;

- whether we can control our costs within the authorized levels of spending, our ability to achieve sustainable efficiencies in our cost structure, the extent to which we incur unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- the amount and timing of additional common stock and debt issuances by Corp to fund equity contributions to us as we incur charges and costs, including fines, that we cannot recover through rates;

- the outcome of the CPUC's investigation into our safety culture, and future legislative or regulatory actions that may be taken to require us to separate our electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

- the outcomes of the SED's investigations of potential violations identified though audits, investigations, or self-reports, including in connection with our September 2016 self-report related to atmospheric corrosion inspections;

- the outcome of future investigations or other enforcement proceedings that may be commenced relating to our compliance with laws, rules, regulations, or orders applicable to our operations, including the construction, expansion or replacement of our electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security; environmental laws and regulations;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge our known and unknown remediation obligations; and the extent to which we are able to recover environmental costs in rates or from other sources;

- the ultimate amount of unrecoverable environmental costs we incur associated with our natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or Nuclear Regulatory Commission ("NRC") regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect our

ability to continue operating Diablo Canyon; whether the CPUC approves the joint proposal that will phase out our Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether we obtain the approvals required to withdraw our NRC application to renew the two Diablo Canyon operating licenses; whether the State Lands Commission could be required to perform an environmental review of the new lands lease as a result of the World Business Academy assertion that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act; and whether we will be able to successfully implement our retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;

- whether we are successful in ensuring physical security of our critical assets and whether our information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether we and our third party vendors and contractors (who host, maintain, modify and update some of our systems) are able to protect our operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether our security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether we can continue to rely on third-party vendors and contractors that maintain and support some of our information technology and operating systems;

- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt our service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by us, our customers, or third parties on which we rely; whether we incur liability to third parties for property damage or personal injury caused by such events; whether we are subject to civil, criminal, or regulatory penalties in connection with such events; and whether our insurance coverage is available for these types of claims and sufficient to cover our liability;

- how the CPUC and the California Air Resources Board implement state environmental laws relating to greenhouse gas, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether we are able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether we are able to timely recover our associated investment costs;

- whether our climate change adaptation strategies are successful;

- the impact that reductions in customer demand for electricity and natural gas have on our ability to make and recover our investments through rates and earn our authorized return on equity, and whether we are successful in addressing the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which we can manage and respond to the volatility of energy commodity prices; our ability and the ability of our counterparties to post or return collateral in connection with price risk management activities; and whether we are able to recover timely our electric generation and energy commodity costs through rates, including our renewable energy procurement costs;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether we can continue to obtain adequate insurance

coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- our ability to access capital markets and other sources of financing in a timely manner on acceptable terms;
- changes in credit ratings which could result in increased borrowing costs especially if we were to lose our investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the more significant risks that could affect the outcome of these forward-looking statements and our future financial condition and results of operations, you should read the sections of the documents incorporated herein by reference titled "Risk Factors" as well as the important factors that may be set forth under the heading "Risk Factors" in the applicable supplement to this prospectus.

You should read this prospectus, any applicable prospectus supplements, the documents that we incorporate by reference into this prospectus, the documents that we have included as exhibits to the registration statement of which this prospectus is a part and the documents that we refer to under the section of this prospectus titled "Where You Can Find More Information" completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statement. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus, the date of the document incorporated by reference or the date of any applicable prospectus supplement. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our historical ratios of earnings to fixed charges for the periods indicated:

| | Nine Months Ended September 30, 2016 | Year Ended December 31, 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|
| Ratio of earnings to fixed charges | 1.57x | 1.67x | 2.55x | 2.23x | 2.24x | 2.51x |

For the purpose of computing the ratios of earnings to fixed charges, “earnings” represent net income adjusted for the income or loss from equity investees of less than 100% affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). “Fixed charges” include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases and allowance for funds used during construction related to the cost of debt and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

## USE OF PROCEEDS

Each prospectus supplement will describe the uses of the proceeds from the issuance of the senior notes offered by that prospectus supplement.

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## DESCRIPTION OF THE SENIOR NOTES

This prospectus describes certain general terms of the senior notes that we may sell from time to time under this prospectus. We will describe the specific terms of each series of senior notes we offer in a prospectus supplement. The senior notes will be issued under an indenture dated as of April 22, 2005 (which supplemented, amended and restated the original indenture dated as of March 11, 2004 as thereafter supplemented) and one or more supplemental indentures that we will enter into with The Bank of New York Mellon Trust Company, N.A. (formerly known as The Bank of New York Trust Company, N.A. and successor to BNY Western Trust Company), as trustee. We have summarized selected provisions of the indenture and the senior notes below. The information we are providing you in this prospectus concerning the senior notes and the indenture is only a summary of the information provided in those documents, and the summary is qualified in its entirety by reference to the provisions of the indenture, including the forms of senior notes attached thereto. You should consult the senior notes themselves and the indenture for more complete information on the senior notes as they, and not this prospectus or any prospectus supplement, govern your rights as a holder. The indenture is included as an exhibit to the registration statement of which this prospectus is a part. The indenture has been qualified under the Trust Indenture Act of 1939, as amended, or the Trust Indenture Act, and the terms of the senior notes will include those made part of the indenture by the Trust Indenture Act.

In this section, references to “we,” “our,” “ours” and “us” refer only to Pacific Gas and Electric Company and not to any of its direct or indirect subsidiaries or affiliates except as expressly provided.

### General

The senior notes are our unsecured general obligations and will rank equally in right of payment to all our other senior and unsubordinated debt. The senior notes will be entitled to the benefit of the indenture equally and ratably with all other senior notes issued under the indenture.

The indenture does not limit the amount of debt we may issue under it or the amount of debt we or our subsidiaries may otherwise incur. We may issue senior notes from time to time under the indenture in one or more series by entering into supplemental indentures or by resolution of our board of directors.

### Provisions of a Particular Series

The prospectus supplement applicable to each series of senior notes will specify, among other things:

- the title of the senior notes;
- any limit on the aggregate principal amount of the senior notes;
- the date or dates on which the principal of the senior notes is payable, including the maturity date, or the method or means by which those dates will be determined, and our right, if any, to extend those dates and the duration of any extension;
- the interest rate or rates of the senior notes, if any, which may be fixed or variable, or the method or means by which the interest rate or rates will be determined, and our ability to extend any interest payment periods and the duration of any extension;
- the date or dates from which any interest will accrue, the dates on which we will pay interest on the senior notes and the regular record date, if any, for determining who is entitled to the interest payable on any interest payment date;
- any periods or periods within which, or date or dates on which, the price or prices at which and the terms and conditions on which the senior notes may be redeemed, in whole or in part, at our option;

- any obligation of ours to redeem, purchase or repay the senior notes pursuant to any sinking fund or other mandatory redemption provisions or at the option of the holder and the terms and conditions upon which the senior notes will be so redeemed, purchased or repaid;
- the denominations in which we will authorize the senior notes to be issued, if other than $1,000 or integral multiples of $1,000;
- whether we will offer the senior notes in the form of global securities and, if so, the name of the depositary for any global securities;
- if the amount payable in respect of principal of or any premium or interest on any senior notes may be determined with reference to an index or other fact or event ascertainable outside the indenture, the manner in which such amount will be determined;
- covenants for the benefit of the holders of that series;
- the currency or currencies in which the principal, premium, if any, and interest on the senior notes will be payable if other than U.S. dollars and the method for determining the equivalent amount in U.S. dollars;
- if the principal of the senior notes is payable from time to time without presentation or surrender, any method or manner of calculating the principal amount that is outstanding at any time for purposes of the indenture; and
- any other terms of the senior notes.

We may sell senior notes at par or at a discount below their stated principal amount or at a premium. We will describe in a prospectus supplement material U.S. federal income tax considerations, if any, and any other special considerations for any senior notes we sell that are denominated in a currency other than U.S. dollars.

**Payment**

Except as may be provided with respect to a series, interest, if any, on the senior notes payable on each interest payment date will be paid to the person in whose name that senior note is registered as of the close of business on the regular record date for the interest payment date. However, interest payable at maturity will be paid to the person to whom the principal is paid. If there has been a default in the payment of interest on any senior notes, the defaulted interest may be paid to the holders of the senior notes as of a date between 10 and 30 days before the date we propose for payment of defaulted interest or in any other manner not inconsistent with the requirements of any securities exchange on which those senior notes may be listed, if the trustee finds it practicable.

**Redemption**

Any terms for the optional or mandatory redemption of a series of senior notes will be set forth in a prospectus supplement for the offered series. Unless otherwise indicated in a prospectus supplement, senior notes will be redeemable by us only upon notice by mail not less than 30 nor more than 60 days before the date fixed for redemption and, if less than all the senior notes of a series are to be redeemed, the particular senior notes to be redeemed will be selected by the method provided for that particular series, or in the absence of any such provision, by such method of random selection as the registrar deems fair and appropriate.

We have reserved the right to provide conditional redemption notices for redemptions at our option or for redemptions that are contingent upon the occurrence or nonoccurrence of an event or condition that cannot be ascertained prior to the time we are required to notify holders of the redemption. A conditional notice may state that if we have not deposited redemption funds with the trustee or a paying agent on or before the redemption date or we have directed the trustee or paying agent not to apply money deposited with it for redemption of senior notes, we will not be required to redeem the senior notes on the redemption date.

**Restrictions on Liens and Sale and Leaseback Transactions**

The indenture does not permit us or any of our significant subsidiaries (as defined below) to, (i) issue, incur, assume or permit to exist any debt (as defined below) secured by a lien (as defined below) on any of our principal property (as defined below) or any of our significant subsidiaries' principal property, whether that principal property was owned when the original indenture was executed (March 11, 2004) or thereafter acquired, unless we provide that the senior notes will be equally and ratably secured with the secured debt or (ii) incur or permit to exist any attributable debt (as defined below) in respect of principal property; provided, however, that the foregoing restriction will not apply to the following:

- to the extent we or a significant subsidiary consolidates with, or merges with or into, another entity, liens on the property of the entity securing debt in existence on the date of the consolidation or merger, provided that the debt and liens were not created or incurred in anticipation of the consolidation or merger and that the liens do not extend to or cover any of our or a significant subsidiary's principal property;

- liens on property acquired after March 11, 2004 and existing at the time of acquisition, as long as the lien was not created or incurred in anticipation thereof and does not extend to or cover any other principal property;

- liens of any kind, including purchase money liens, conditional sales agreements or title retention agreements and similar agreements, upon any property acquired, constructed, developed or improved by us or a significant subsidiary (whether alone or in association with others) which do not exceed the cost or value of the property acquired, constructed, developed or improved and which are created prior to, at the time of, or within 12 months after the acquisition (or in the case of property constructed, developed or improved, within 12 months after the completion of the construction, development or improvement and commencement of full commercial operation of the property, whichever is later) to secure or provide for the payment of any part of the purchase price or cost thereof; provided that the liens do not extend to any principal property other than the property so acquired, constructed, developed or improved;

- liens in favor of the United States, any state or any foreign country or any department, agency or instrumentality or any political subdivision of the foregoing to secure payments pursuant to any contract or statute or to secure any indebtedness incurred for the purpose of financing all or any part of the purchase price or cost of constructing or improving the property subject to the lien, including liens related to governmental obligations the interest on which is tax-exempt under Section 103 of the Internal Revenue Code of 1986, as amended, or the Code, or any successor section of the Code;

- liens in favor of us, one or more of our significant subsidiaries, one or more of our wholly owned subsidiaries or any of the foregoing combination; and

- replacements, extensions or renewals (or successive replacements, extensions or renewals), in whole or in part, of any lien or of any agreement referred to in the bullet points above or replacements, extensions or renewals of the debt secured thereby (to the extent that the amount of the debt secured by the lien is not increased from the amount originally so secured, plus any premium, interest, fee or expenses payable in connection with any replacements, refundings, refinancings, remarketings, extensions or renewals); provided that replacement, extension or renewal is limited to all or a part of the same property (plus improvements thereon or additions or accessions thereto) that secured the lien replaced, extended or renewed.

Notwithstanding the restriction described above, we or any significant subsidiary may, (i) issue, incur or assume debt secured by a lien not described in the immediately preceding six bullet points on any principal property owned at March 11, 2004 or thereafter acquired without providing that the outstanding senior notes be equally and ratably secured with that debt and (ii) issue or permit to exist attributable debt in respect of principal property, in either case, so long as the aggregate amount of that secured debt and attributable debt, together with

the aggregate amount of all other debt secured by liens on principal property not described in the immediately preceding six bullet points then outstanding and all other attributable debt in respect of principal property, does not exceed 10% of our net tangible assets, as determined by us as of a month end not more than 90 days prior to the closing or consummation of the proposed transaction.

For these purposes:

- "attributable debt" in respect of a sale and leaseback transaction means, at the time of determination, the present value of the obligation of the lessee for net rental payments during the remaining term of the lease included in the sale and leaseback transaction, including any period for which the lease has been extended or may, at the option of the lessor, be extended. The present value shall be calculated using a discount rate equal to the rate of interest implicit in the transaction, determined in accordance with generally accepted accounting principals, or GAAP.

- "capital lease obligation" means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet in accordance with GAAP.

- "debt" means any debt of ours for money borrowed and guarantees by us of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- "debt" of a significant subsidiary means any debt of such significant subsidiary for money borrowed and guarantees by the significant subsidiary of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- "excepted property" means any right, title or interest of us or any of our significant subsidiaries in, to or under any of the following property, whether owned at March 11, 2004 or thereafter acquired:

  - all money, investment property and deposit accounts (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), and all cash on hand or on deposit in banks or other financial institutions, shares of stock, interests in general or limited partnerships or limited liability companies, bonds, notes, other evidences of indebtedness and other securities, of whatever kind and nature;

  - all accounts, chattel paper, commercial tort claims, documents, general intangibles, instruments, letter-of-credit rights and letters of credit (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), with certain exclusions such as licenses and permits to use the real property of others, and all contracts, leases (other than the lease of certain real property at our Diablo Canyon power plant), operating agreements and other agreements of whatever kind and nature; and all contract rights, bills and notes;

  - all revenues, income and earnings, all accounts receivable, rights to payment and unbilled revenues, and all rents, tolls, issues, product and profits, claims, credits, demands and judgments, including any rights in or to rates, revenue components, charges, tariffs, or amounts arising therefrom, or in any amounts that are accrued and recorded in a regulatory account for collection by us or any significant subsidiary;

  - all governmental and other licenses, permits, franchises, consents and allowances including all emission allowances (or similar rights) created under any similar existing or future law relating to abatement or control of pollution of the atmosphere, water or soil, other than all licenses and permits to use the real property of others, franchises to use public roads, streets and other public properties, rights of way and other rights, or interests relating to the occupancy or use of real property;

  - all patents, patent licenses and other patent rights, patent applications, trade names, trademarks, copyrights and other intellectual property, including computer software and software licenses;

  - all claims, credits, choses in action, and other intangible property;
  - all automobiles, buses, trucks, truck cranes, tractors, trailers, motor vehicles and similar vehicles and movable equipment; all rolling stock, rail cars and other railroad equipment; all vessels, boats, barges and other marine equipment; all airplanes, helicopters, aircraft engines and other flight equipment; and all parts, accessories and supplies used in connection with any of the foregoing;
  - all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; all materials, supplies, inventory and other items of personal property that are consumable (otherwise than by ordinary wear and tear) in their use in the operation of the principal property; all fuel, whether or not that fuel is in a form consumable in the operation of the principal property, including separate components of any fuel in the forms in which those components exist at any time before, during or after the period of the use thereof as fuel; all hand and other portable tools and equipment; and all furniture and furnishings;
  - all personal property the perfection of a security interest in which is not governed by the California Commercial Code;
  - all oil, gas and other minerals (as those terms are defined in the California Commercial Code as in effect on March 11, 2004) and all coal, ore, gas, oil and other minerals and all timber, and all rights and interests in any of the foregoing, whether or not the minerals or timber have been mined or extracted or otherwise separated from the land; and all electric energy and capacity, gas (natural or artificial), steam, water and other products generated, produced, manufactured, purchased or otherwise acquired by us or any significant subsidiary;
  - all property which is the subject of a lease agreement other than a lease agreement that results from a sale and leaseback transaction designating us or any significant subsidiary as lessee and all our, or a significant subsidiary's right, title and interest in and to that property and in, to and under that lease agreement, whether or not that lease agreement is intended as security (other than certain real property leased at our Diablo Canyon power plant and the related lease agreement);
  - real, personal and mixed properties of an acquiring or acquired entity unless otherwise made a part of principal property; and
  - all proceeds (as that term is defined in the California Commercial Code as in effect on March 11, 2004) of the property listed in the preceding bullet points.

- "lien" means any mortgage, deed of trust, pledge, security interest, encumbrance, easement, lease, reservation, restriction, servitude, charge or similar right and any other lien of any kind, including, without limitation, any conditional sale or other title retention agreement, any lease of a similar nature, and any defect, irregularity, exception or limitation in record title or, when the context so requires, any lien, claim or interest arising from anything described in this bullet point.
- "net tangible assets" means the total amount of our assets determined on a consolidated basis in accordance with GAAP, less (i) the sum of our consolidated current liabilities determined in accordance with GAAP and (ii) the amount of our consolidated assets classified as intangible assets determined in accordance with GAAP, including, but not limited to, such items as goodwill, trademarks, trade names, patents, and unamortized debt discount and expense and regulatory assets carried as an asset on our consolidated balance sheet.
- "principal property" means any property of ours or any of our significant subsidiaries, as applicable, other than excepted property.
- "significant subsidiary" has the meaning specified in Rule 1-02(w) of Regulation S-X under the Securities Act of 1933, as amended, or the Securities Act; provided that, significant subsidiary shall not include any corporation or other entity substantially all the assets of which are excepted property.

- “swap agreement” means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions.

**Consolidation, Merger, Conveyance or Other Transfer**

We may not consolidate with or merge with or into any other person (as defined below) or convey, otherwise transfer or lease all or substantially all of our principal property to any person unless:

- the person formed by that consolidation or into which we are merged or the person which acquires by conveyance or other transfer, or which leases, all or substantially all of the principal property is a corporation, partnership, limited liability company, association, company, joint stock company or business trust, organized and existing under the laws of the United States, or any state thereof or the District of Columbia;

- the person executes and delivers to the trustee a supplemental indenture that in the case of a consolidation, merger, conveyance or other transfer, or in the case of a lease if the term thereof extends beyond the last stated maturity of the senior notes then outstanding, contains an assumption by the successor person of the due and punctual payment of the principal of and premium, if any, and interest, if any, on all senior notes then outstanding and the performance and observance of every covenant and condition under the indenture to be performed or observed by us;

- in the case of a lease, the lease is made expressly subject to termination by us or by the trustee at any time during the continuance of an event of default under the indenture;

- immediately after giving effect to the transaction and treating any indebtedness that becomes our obligation as a result of the transaction as having been incurred by us at the time of the transaction, no default or event of default under the indenture shall have occurred and be continuing; and

- we have delivered to the trustee an officer’s certificate and an opinion of counsel, each stating that the merger, consolidation, conveyance, lease or transfer, as the case may be, fully complies with all provisions of the indenture; provided, however, that the delivery of the officer’s certificate and opinion of counsel shall not be required with respect to any merger, consolidation, conveyance, lease or transfer between us and any of our wholly owned subsidiaries.

Notwithstanding the foregoing, we may merge or consolidate with or transfer all or substantially all of our assets to an affiliate that has no significant assets or liabilities and was formed solely for the purpose of changing our jurisdiction of organization or our form of organization or for the purpose of forming a holding company; provided that the amount of our indebtedness is not increased; and provided, further that the successor assumes all of our obligations under the indenture.

In the case of the conveyance or other transfer of all or substantially all of our principal property to any person as contemplated under the indenture, upon the satisfaction of all the conditions described above, we (as we would exist without giving effect to the transaction) would be released and discharged from all obligations and covenants under the indenture and under the senior notes then outstanding unless we elect to waive the release and discharge.

The meaning of the term “substantially all” has not been definitely established and is likely to be interpreted by reference to applicable state law if and at the time the issue arises and will depend on the facts and circumstances existing at the time.

For these purposes, “person” means any individual, corporation, partnership, limited liability company, association, company, joint stock company, limited liability partnership, joint venture, trust or unincorporated organization, or any other entity whether or not a legal entity, or any governmental authority.

**Additional Covenants**

We have agreed in the indenture, among other things:

- to maintain a place of payment;
- to maintain our corporate existence (subject to the provisions above relating to mergers and consolidations); and
- to deliver to the trustee an annual officer's certificate with respect to our compliance with our obligations under the indenture.

**Modification of the Indenture; Waiver**

We and the trustee may, with the consent of the holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the indenture, considered as one class, modify or amend the indenture, including the provisions relating to the rights of the holders of senior notes of the affected series. However, no modification or amendment may, without the consent of each holder of affected senior notes:

- change the stated maturity (except as provided by the terms of a series of senior notes) of the principal of, or interest on, the senior note or reduce the principal amount or any premium payable on the senior note or reduce the interest rate of the senior note, or change the method of calculating the interest rate with respect to the senior note;
- reduce the amount of principal of any discount senior note that would be payable upon acceleration of the maturity of the senior note;
- change the coin, currency or other property in which the senior note or interest or premium on the senior note is payable;
- impair the right to institute suit for the enforcement of any payment on the senior note;
- reduce the percentage in principal amount of outstanding senior notes the consent of whose holders is required for modification or amendment of the indenture or for waiver of compliance with certain provisions of the indenture or for waiver of defaults;
- reduce the quorum or voting requirements applicable to holders of the senior notes; or
- modify the provisions of the indenture with respect to modification and waiver, except as provided in the indenture.

We and the trustee may, without the consent of any holder of senior notes, modify and amend the indenture for certain purposes, including to:

- add covenants or other provisions applicable to us and for the benefit of the holders of senior notes or one or more specified series thereof or to surrender any right or power conferred on us;
- cure any ambiguity or to correct or supplement any provision of the indenture which may be defective or inconsistent with other provisions;
- make any other additions to, deletions from or changes to the provisions under the indenture so long as the additions, deletions or changes do not materially adversely affect the holders of any series of senior notes in any material respect;
- change or eliminate any provision of the indenture or add any new provision so long as the change, elimination or addition does not adversely affect the interests of holders of senior notes of any series in any material respect; and

- change any place or places for payment or surrender of senior notes and where notices and demands to us may be served.

The holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the indenture, voting as a single class, may waive compliance by us with our covenant in respect of our corporate existence and the covenants described under “Restrictions on Liens and Sale and Leaseback Transactions” and “Consolidation, Merger, Conveyance or Transfer” and with certain covenants and restrictions that may apply to a series of senior notes as provided in the indenture. The holders of not less than a majority in aggregate principal amount of the senior notes outstanding may, on behalf of the holders of all of the senior notes, waive any past default under the indenture and its consequences, except a default in the payment of the principal of or any premium or interest on any senior note and defaults in respect of a covenant or provision in the indenture which cannot be modified, amended or waived without the consent of each holder of affected senior notes.

In order to determine whether the holders of the requisite principal amount of the outstanding senior notes have taken an action under the indenture as of a specified date:

- the principal amount of a discount senior note that will be deemed to be outstanding will be the amount of the principal that would be due and payable as of that date upon acceleration of the maturity to that date; and

- senior notes owned by us or any other obligor upon the senior notes or any of our or their affiliates will be disregarded and deemed not to be outstanding.

**Events of Default**

An “event of default” means any of the following events which shall occur and be continuing:

- failure to pay interest on a senior note within 30 days after the interest becomes due and payable;

- failure to pay the principal of, or sinking fund payment or premium, if any, on, a senior note when due and payable;

- failure to perform or breach of any other covenant or warranty applicable to us in the indenture continuing for 90 days after the trustee gives us, or the holders of at least 33% in aggregate principal amount of the senior notes then outstanding give us and the trustee, written notice specifying the default or breach and requiring us to remedy the default or breach, unless the trustee or the trustee and holders of a principal amount of senior notes not less than the principal amount of senior notes the holders of which gave that notice agree in writing to an extension of the period prior to its expiration;

- certain events of bankruptcy, insolvency or reorganization; and

- the occurrence of any event of default as defined in any mortgage, indenture or instrument under which there may be issued, or by which there may be secured or evidenced, any of our debt, whether the debt existed on March 23, 2004 (the date senior notes were first issued under the original indenture), or is thereafter created, if the event of default: (i) is caused by a failure to pay principal after final maturity of the debt after the expiration of the grace period provided in the debt (which we refer to as a “payment default”) or (ii) results in the acceleration of the debt prior to its express maturity, and, in each case, the principal amount of the debt, together with the principal amount of any other debt under which there has been a payment default or the maturity of which has been so accelerated, aggregates $100 million or more.

The $100 million amount specified in the bullet point above shall be increased in any calendar year subsequent to 2004 by the same percentage increase in the urban CPI for the period commencing January 1, 2004

and ending on January 1 of the applicable calendar year. "Debt" for the purpose of the bullet point above means any debt of ours for money borrowed but, in each case, excluding liabilities in respect of capital lease obligations or swap agreements.

If the trustee deems it to be in the interest of the holders of the senior notes, it may withhold notice of default, except defaults in the payment of principal of or interest or premium on or with respect to, any senior note.

If an event of default occurs and is continuing, the trustee or the holders of not less than 33% in aggregate principal amount of the senior notes outstanding, considered as one class, may declare all principal due and payable immediately by notice in writing to us (and to the trustee if given by holders); provided, however, that if an event of default occurs with respect to the specified events of bankruptcy, insolvency or reorganization, then the senior notes outstanding shall be due and payable immediately without further action by the trustee or holders. If, after such a declaration of acceleration, we pay or deposit with the trustee all overdue interest and principal and premium on senior notes that would have been due otherwise, plus any interest and other conditions specified in the indenture have been satisfied before a judgment or decree for payment has been obtained by the trustee as provided in the indenture, the event or events of default giving rise to the acceleration will be deemed to have been waived and the declaration of acceleration and its consequences will be deemed to have been rescinded and annulled.

No holder of senior notes will have any right to enforce any remedy under the indenture unless the holder has given the trustee written notice of a continuing event of default, the holders of at least 33% in aggregate principal amount of the senior notes outstanding have requested the trustee in writing to institute proceedings in respect of the event of default in its own name as trustee under the indenture and the holder or holders have offered the trustee reasonable indemnity against costs, expenses and liabilities with respect to the request, the trustee has failed to institute any proceeding within 60 days after receiving the notice from holders, and no direction inconsistent with the written request has been given to the trustee during the 60-day period by holders of at least a majority in aggregate principal amount of senior notes then outstanding.

The trustee is not required to risk its funds or to incur financial liability if there is a reasonable ground for believing that repayment to it or adequate indemnity against risk or liability is not reasonably assured.

If an event of default has occurred and is continuing, holders of not less than a majority in principal amount of the senior notes then outstanding generally may direct the time, method and place of conducting any proceedings for any remedy available to the trustee, or exercising any trust or power conferred upon the trustee; provided the direction could not involve the trustee in personal liability where indemnity would not, in the trustee's sole discretion, be adequate.

**Satisfaction and Discharge**

Any senior note, or any portion of the principal amount thereof, will be deemed to have been paid for purposes of the indenture, and our entire indebtedness in respect of the senior notes will be deemed to have been satisfied and discharged, if certain conditions are satisfied, including an irrevocable deposit with the trustee or any paying agent (other than us) in trust of:

- money in an amount which will be sufficient; or
- in the case of a deposit made prior to the maturity of the senior notes or portions thereof, eligible obligations (as described below) which do not contain provisions permitting the redemption or other prepayment thereof at the option of the issuer thereof, the principal of and the interest on which when due, without any regard to reinvestment thereof, will provide monies which, together with the money, if any, deposited with or held by the trustee or the paying agent, will be sufficient; or
- a combination of either of the two items described in the two preceding bullet points which will be sufficient;

to pay when due the principal of and premium, if any, and interest, if any, due and to become due on the senior notes or portions thereof.

This discharge of the senior notes through the deposit with the trustee of cash or eligible obligations generally will be treated as a taxable disposition for U.S. federal income tax purposes by the holders of those senior notes. Prospective investors in the senior notes should consult their own tax advisors as to the particular U.S. federal income tax consequences applicable to them in the event of such discharge.

For this purpose, "eligible obligations" for U.S. dollar-denominated senior notes, means securities that are direct obligations of, or obligations unconditionally guaranteed by, the United States, entitled to the benefit of the full faith and credit thereof, or depositary receipts issued by a bank as custodian with respect to these obligations or any specific interest or principal payments due in respect thereof held by the custodian for the account of the holder of a depositary receipt.

**Transfer and Exchange**

Senior notes of any series may be exchanged for other senior notes of the same series of authorized denominations and of like aggregate principal amount and tenor. Subject to the terms of the indenture and the limitations applicable to global securities, senior notes may be presented for exchange or registration of transfer at the office of the registrar without service charge (unless otherwise indicated in a prospectus supplement), upon payment of any taxes and other governmental charges imposed on registration of transfer or exchange. Such transfer or exchange will be effected upon the trustee, us or the registrar, as the case may be, being satisfied with the instruments of transfer.

If we provide for any redemption of a series of senior notes, we will not be required to execute, register the transfer of or exchange any senior note of that series for 15 days before a notice of redemption is mailed or register the transfer of or exchange any senior note selected for redemption.

**Global Securities**

Unless we indicate differently in a prospectus supplement, senior notes initially will be issued in book-entry form and represented by one or more global securities (collectively, the "global securities"), with an aggregate principal amount equal to that of the senior notes they represent. The global securities will be deposited with, or on behalf of, The Depository Trust Company, New York, New York, as depositary ("DTC"), and registered in the name of Cede & Co., the nominee of DTC. Unless and until it is exchanged for individual certificates evidencing securities under the limited circumstances described below, a global security may not be transferred except as a whole by the depositary to its nominee or by the nominee to the depositary, or by the depositary or its nominee to a successor depositary or to a nominee of the successor depositary.

DTC has advised us that it is:

- a limited-purpose trust company organized under the New York Banking Law;
- a "banking organization" within the meaning of the New York Banking Law;
- a member of the Federal Reserve System;
- a "clearing corporation" within the meaning of the New York Uniform Commercial Code; and
- a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934.

DTC holds securities that its participants deposit with DTC. DTC also facilitates the settlement among its participants of securities transactions, including transfers and pledges, in deposited securities through electronic

computerized book-entry changes in participants' accounts, which eliminates the need for physical movement of securities certificates. "Direct participants" in DTC include securities brokers and dealers, including underwriters, banks, trust companies, clearing corporations and other organizations. DTC is a wholly owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC National Securities Clearance Corporation, all of which are registered clearing agencies, DTC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others, referred to as "indirect participants," that clear transactions through or maintain a custodial relationship with a direct participant either directly or indirectly. The rules applicable to DTC and its participants are on file with the SEC.

Purchases of securities within the DTC system must be made by or through direct participants, which will receive a credit for those securities on DTC's records. The ownership interest of the actual purchaser of a security, which we sometimes refer to as a "beneficial owner," is in turn recorded on the direct and indirect participants' records. Beneficial owners of securities will not receive written confirmation from DTC of their purchases. However, beneficial owners are expected to receive written confirmations providing details of their transactions, as well as periodic statements of their holdings, from the direct or indirect participants through which they purchased securities. Transfers of ownership interests in global securities are to be accomplished by entries made on the books of participants acting on behalf of beneficial owners. Beneficial owners will not receive certificates representing their ownership interests in the global securities except under the limited circumstances described below.

To facilitate subsequent transfers, all global securities deposited by direct participants with DTC will be registered in the name of DTC's partnership nominee, Cede & Co, or such other name as may be requested by an authorized representative of DTC. The deposit of securities with DTC and their registration in the name of Cede & Co. or such other nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual beneficial owners of the securities. DTC's records reflect only the identity of the direct participants to whose accounts the securities are credited, which may or may not be the beneficial owners. The direct and indirect participants are responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to direct participants, by direct participants to indirect participants and by direct participants and indirect participants to beneficial owners will be governed by arrangements among them, subject to any legal requirements in effect from time to time. Beneficial owners of securities may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the securities, such as redemptions, tenders, defaults, and proposed amendments to the security documents. For example, beneficial owners of securities may wish to ascertain that the nominee holding the securities for their benefit has agreed to obtain and transmit notices to beneficial owners. In the alternative, beneficial owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices will be sent to DTC or its nominee. If less than all of the securities of a particular series are being redeemed, DTC's practice is to determine by lot the amount of the interest of each direct participant in such issue to be redeemed.

In any case where a vote may be required with respect to securities of a particular series, neither DTC nor Cede & Co. (nor any other DTC nominee) will give consents for or vote the global securities, unless authorized by a direct participant in accordance with DTC's procedures. Under its usual procedures, DTC will mail an omnibus proxy to us as soon as possible after the record date. The omnibus proxy assigns the consenting or voting rights of Cede & Co. to those direct participants to whose accounts the securities of such series are credited on the record date identified in a listing attached to the omnibus proxy.

Principal and interest payments on the securities will be made to Cede & Co., as or such other nominee as may be requested by authorized representative of DTC. DTC's practice is to credit direct participants' accounts upon receipt of funds and corresponding detail information from us or the paying agent in accordance with their respective holdings shown on DTC's records. Payments by direct and indirect participants to beneficial owners will be governed by standing instructions and customary practices, as is the case with securities held for the

account of customers in bearer form or registered in "street name." Those payments will be the responsibility of participants and not of DTC, the paying agent or us, subject to any legal requirements in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may otherwise be requested by an authorized representative of DTC) is our responsibility, disbursement of payments to direct participants is the responsibility of DTC and disbursement of payments to the beneficial owners is the responsibility of direct and indirect participants.

Except under the limited circumstances described below, purchasers of securities will not be entitled to have securities registered in their names and will not receive physical delivery of securities. Accordingly, each beneficial owner must rely on the procedures of DTC and its participants to exercise any rights under the securities and the applicable indenture.

The laws of some jurisdictions may require that some purchasers of securities take physical delivery of securities in definitive form. Those laws may impair the ability to transfer or pledge beneficial interests in securities.

DTC may discontinue providing its services as securities depository with respect to the securities at any time by giving us reasonable notice. Under such circumstances, in the event that a successor securities depository is not obtained, certificates representing the securities are required to be printed and delivered. Also, we may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository), in which event, certificates representing the securities will be printed and delivered to DTC.

We have obtained the information in this section and elsewhere in this prospectus concerning DTC and DTC's book-entry system from sources that are believed to be reliable, but we take no responsibility for the accuracy of this information.

**Resignation or Removal of Trustee**

The trustee may resign at any time upon written notice to us and the trustee may be removed at any time by written notice delivered to the trustee and us and signed by the holders of at least a majority in principal amount of the outstanding senior notes. No resignation or removal of a trustee will take effect until a successor trustee accepts appointment. In addition, under certain circumstances, we may remove the trustee. We must give notice of resignation and removal of the trustee or the appointment of a successor trustee to all holders of senior notes as provided in the indenture.

**Trustees, Paying Agents and Registrars for the Senior Notes**

The Bank of New York Mellon Trust Company, N.A. acts as the trustee, paying agent and registrar under the indenture. We may change either the paying agent or registrar without prior notice to the holders of the senior notes, and we may act as paying agent. We and our affiliates maintain ordinary banking and trust relationships with a number of banks and trust companies, including The Bank of New York Mellon Trust Company, N.A.

**Governing Law**

The indenture and the senior notes are governed by California law.

**PLAN OF DISTRIBUTION**

We may sell any series of senior notes being offered by this prospectus in one or more of the following ways from time to time:

- to underwriters or dealers for resale to the public or to institutional investors;
- directly to institutional investors; or
- through agents to the public or to institutional investors.

A prospectus supplement applicable to each series of senior notes will state the terms of the offering of the senior notes, including:

- the name or names of any underwriters or agents;
- the purchase price of the senior notes and the proceeds to be received by us from the sale;
- any underwriting discounts or agency fees and other items constituting underwriters' or agents' compensation;
- any initial public offering price;
- any discounts or concessions allowed or reallowed or paid to dealers; and
- any securities exchange or automated quotation system on which the senior notes may be listed.

If we use underwriters in the sale, the senior notes will be acquired by the underwriters for their own accounts and may be resold from time to time in one or more transactions, including:

- negotiated transactions;
- at a fixed public offering price or prices, which may be changed;
- at market prices prevailing at the time of sale;
- at prices based on prevailing market prices; or
- at negotiated prices.

Senior notes may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more of those firms. The specific managing underwriter or underwriters, if any, will be named in the prospectus supplement relating to the particular senior notes together with the members of the underwriting syndicate, if any. Unless otherwise set forth in a prospectus supplement, the obligations of the underwriters to purchase the particular senior notes will be subject to certain conditions precedent and the underwriters will be obligated to purchase all of the senior notes being offered if any are purchased.

We may sell senior notes directly or through agents we designate from time to time. The prospectus supplement will set forth the name of any agent involved in the offer or sale of senior notes in respect of which such prospectus supplement is delivered and any commissions payable by us to such agent. Unless otherwise indicated in a prospectus supplement, any agent will be acting on a best efforts basis for the period of its appointment.

Any underwriters, dealers or agents participating in the distribution of senior notes may be deemed to be underwriters as defined in the Securities Act, and any discounts or commissions received by them on the sale or resale of senior notes may be deemed to be underwriting discounts and commissions under the Securities Act. We may agree with the underwriters, dealers and agents to indemnify them against certain civil liabilities, including liabilities under the Securities Act or to contribute with respect to payments which the underwriters, dealers or agents may be required to make in respect of these liabilities.

Unless otherwise specified in a prospectus supplement, senior notes will not be listed on a securities exchange. Any underwriters to whom senior notes are sold by us for public offering and sale may make a market in the senior notes, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice.

To facilitate a senior notes offering, any underwriter may engage in over-allotment, short covering transactions and penalty bids or stabilizing transactions in accordance with Regulation M under the Securities Exchange Act of 1934.

- Over-allotment involves sales in excess of the offering size, which creates a short position.

- Stabilizing transactions permit bids to purchase the underlying senior notes so long as the stabilizing bids do not exceed a specified maximum.

- Short covering positions involve purchases of senior notes in the open market after the distribution is completed to cover short positions.

- Penalty bids permit the underwriters to reclaim a selling concession from a dealer when senior notes originally sold by the dealer are purchased in a covering transaction to cover short positions.

These activities may cause the price of the senior notes to be higher than it otherwise would be. If commenced, these activities may be discontinued by the underwriters at any time.

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## EXPERTS

The consolidated financial statements and the related financial statement schedule, incorporated in this prospectus by reference from the Company's Annual Report on Form 10-K, and the effectiveness of Pacific Gas and Electric Company's internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports, which are incorporated herein by reference. Such financial statements and financial statement schedule have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

## LEGAL MATTERS

The validity of the senior notes has been passed upon for us by Orrick, Herrington & Sutcliffe LLP. The validity of the senior notes will be passed upon for any agents, dealers or underwriters by their counsel named in the applicable prospectus supplement.

## WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, information statements and other information with the SEC under File No. 001-2348. These SEC filings are available to the public over the Internet at the SEC's website at http://www.sec.gov. You may also read and copy any of these SEC filings at the SEC's public reference room at 100 F Street, N.E., Washington D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330.

## CERTAIN DOCUMENTS INCORPORATED BY REFERENCE

We have "incorporated by reference" into this prospectus certain information that we file with the SEC. This means that we can disclose important business, financial and other information in this prospectus by referring you to the documents containing this information.

We incorporate by reference the documents listed below and all future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 (other than information deemed to be furnished and not filed) on or (1) after the date of the filing of the registration statement containing this prospectus and prior to the effectiveness of such registration statement and (2) after the date of this prospectus and prior to the termination of any offering of the senior notes made hereby:

- our Annual Report on Form 10-K for the year ended December 31, 2015;
- our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2016, June 30, 2016 and September 30, 2016; and
- our Current Reports on Form 8-K filed with the SEC on February 19, 2016, February 23, 2016, February 29, 2016 (excluding Item 7.01), March 1, 2016, March 4, 2016, March 22, 2016, April 12, 2016, May 2, 2016, May 9, 2016, May 23, 2016, May 24, 2016, May 25, 2016, June 2, 2016, June 21, 2016, June 27, 2016, July 6, 2016, August 1, 2016, August 2, 2016, August 3, 2016, August 4, 2016, August 10, 2016, August 19, 2016, August 19, 2016, August 31, 2016 (excluding Item 7.01 and Item 9.01), September 2, 2016 (excluding Item 7.01), September 21, 2016 (excluding Item 7.01), November 14, 2016 (excluding Item 7.01 and Item 9.01), November 18, 2016, November 22, 2016, December 1, 2016, December 2, 2016 (excluding Item 7.01), December 21, 2016 and January 11, 2017 (excluding Item 7.01).

The incorporation by reference of the filings listed above does not extend to any such filings made by Corp and not us or to any information in any filings jointly made by Corp and us regarding Corp or its other subsidiaries, but not regarding us.

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All information incorporated by reference is deemed to be part of this prospectus except to the extent that the information is updated or superseded by information filed with the SEC after the date the incorporated information was filed (including later-dated reports listed above) or by the information contained in this prospectus or the applicable prospectus supplement. Any information that we subsequently file with the SEC that is incorporated by reference, as described above, will automatically update and supersede as of the date of such filing any previous information that had been part of this prospectus or the applicable prospectus supplement, or that had been incorporated herein by reference.

You may request a copy of these filings at no cost by writing or contacting us at the following address:

The Office of the Corporate Secretary
PG&E Corporation
77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
Telephone: (415) 973-8200
Facsimile: (415) 973-8719

$
$ % Senior Notes due
$ 4.00% Senior Notes due December 1, 2046

PROSPECTUS SUPPLEMENT

, 2017

*Joint Book-Running Managers*

**BNP PARIBAS**
**Goldman, Sachs & Co.**
**RBC Capital Markets**
**Wells Fargo Securities**

*Co-Managers*

**BNY Mellon Capital Markets, LLC**
**TD Securities**
**Blaylock Beal Van, LLC**
**MFR Securities, Inc.**

# Exhibit 22

Filed pursuant to Rule 424(b)(3)
Registration Statement No. 333-224091

**PROSPECTUS**

# Pacific Gas and Electric Company

**OFFER TO EXCHANGE**

**This is an offer by Pacific Gas and Electric Company (the "Company"), a subsidiary of PG&E Corporation ("Corp"), to exchange up to $500,000,000 aggregate principal amount of its Floating Rate Senior Notes due November 28, 2018 (the "2018 Restricted Notes"), $1,150,000,000 aggregate principal amount of its 3.30% Senior Notes due December 1, 2027 (the "2027 Restricted Notes") and $850,000,000 aggregate principal amount of its 3.95% Senior Notes due December 1, 2047 (the "2047 Restricted Notes", and together with the 2018 Restricted Notes and 2027 Restricted Notes, the "Restricted Notes") that were issued pursuant to a private offering on November 29, 2017, for a like aggregate principal amount of Floating Rate Senior Notes due November 28, 2018 (the "2018 Exchange Notes"), 3.30% Senior Notes due December 1, 2027 (the "2027 Exchange Notes") and 3.95% Senior Notes due December 1, 2047 (the "2047 Exchange Notes", and together with the 2018 Exchange Notes and 2027 Exchange Notes, the "Exchange Notes"), respectively, in a transaction registered under the Securities Act of 1933, as amended (the "Securities Act") (the "Exchange Offer"). We refer to the 2027 Exchange Notes and the 2047 Exchange Notes as the "Fixed Rate Exchange Notes".**

**The Exchange Offer is subject to customary closing conditions and will expire at 5:00 p.m., New York City time, on May 14, 2018, unless we extend the Exchange Offer.**

The Exchange Offer:

- We will exchange equal principal amounts of 2018 Exchange Notes, 2027 Exchange Notes and 2047 Exchange Notes for all outstanding 2018 Restricted Notes, 2027 Restricted Notes and 2047 Restricted Notes, respectively, that are validly tendered and not validly withdrawn prior to the expiration or termination of the Exchange Offer.
- You may withdraw tenders of the Restricted Notes at any time prior to the expiration or termination of the Exchange Offer.
- The terms of the Exchange Notes are identical in all material respects to those of the outstanding Restricted Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the Restricted Notes do not apply to the Exchange Notes.
- The exchange of the Restricted Notes for the Exchange Notes will not be a taxable transaction for United States federal income tax purposes, but you should see the discussion under the caption "Material U.S. Federal Income Tax Consequences" for more information.
- We will not receive any proceeds from the Exchange Offer.
- We issued the Restricted Notes in a transaction not requiring registration under the Securities Act and, as a result, their transfer is restricted. We are making the Exchange Offer to satisfy your registration rights as a holder of the Restricted Notes.

The Exchange Notes will be direct, unsecured and unsubordinated obligations of the Company and will rank equally with all our other existing and future unsecured and unsubordinated obligations. The Exchange Notes will be effectively subordinated to all our secured debt. For a more detailed description of the Exchange Notes, see "Description of the Exchange Notes".

The Exchange Notes, together with any Restricted Notes that are not exchanged in the Exchange Offer, will be governed by the same indenture, constitute the same class of debt securities for the purposes of the indenture and vote together on all matters.

Each broker-dealer that receives the Exchange Notes for its own account pursuant to the Exchange Offer must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of such Exchange Notes. The letter of transmittal accompanying this prospectus states that, by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the Exchange Notes received in exchange for the Restricted Notes where such Restricted Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. Under the registration rights agreement, we have agreed to make available a prospectus in conformity in all material respects with the requirements of the Securities Act and the Trust Indenture Act of 1939, as amended, to any participating broker-dealer for use in connection with any resale of any Exchange Notes acquired in the Exchange Offer for the period beginning when the Exchange Notes are first issued in the Exchange Offer and ending upon the earlier of the expiration of the 30th day after the Exchange Offer has been completed or such time as such broker-dealers no longer own any Restricted Notes. See "Plan of Distribution".

All untendered Restricted Notes will continue to be subject to the restrictions on transfer set forth in the outstanding Restricted Notes and in the indenture. In general, the Restricted Notes may not be offered or sold, unless registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and other applicable securities laws. Other than in connection with the Exchange Offer, we do not currently anticipate that we will register the Restricted Notes under the Securities Act.

There is no established trading market for the Exchange Notes. We do not plan to list the Exchange Notes on any securities exchange or any automated dealer quotation system.

**See "Risk Factors" beginning on page 15 for a discussion of risks you should consider prior to tendering your outstanding Restricted Notes for exchange.**

**Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.**

**The date of this prospectus is April 13, 2018.**

We have not authorized any person to provide any information or to make any representation other than the information contained or incorporated by reference in this prospectus, and if any person provides any of this information or makes any representation of this kind, that information or representation must not be relied upon as having been authorized by us. If you receive any other information, you should not rely on it. We are not making the Exchange Offer to, nor will we accept surrenders for exchange from, holders of outstanding Restricted Notes in any jurisdiction in which the applicable Exchange Offer would not be in compliance with the securities or blue sky laws of such jurisdiction or where it is otherwise unlawful. This prospectus may only be used where it is legal to sell these securities. You should assume that the information contained in this prospectus is accurate only as of its date, and that any information we have incorporated by reference is accurate only as of the date of the document incorporated by reference. Our business, financial condition, results of operations and prospects may have changed since those dates.

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Pacific Gas and Electric Company is a California corporation. The mailing address of our principal executive offices is 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and our telephone number at that location is (415) 973-7000.

Unless otherwise indicated, when used in this prospectus, the terms “we,” “our,” “us” and “the Company” refer to Pacific Gas and Electric Company and its subsidiaries, and the term “Corp” refers to our parent, PG&E Corporation.

## WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). Our SEC filings are available to the public from the SEC's web site at www.sec.gov. You may also read and copy any document we file at the SEC's public reference room in Washington, D.C. located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may also obtain copies of any document we file at prescribed rates by writing to the Public Reference Section of the SEC at that address. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. Information about us, including our SEC filings, is also available on our website at www.pge.com. **Our website and the information contained therein or connected thereto shall not be deemed to be incorporated into this prospectus and you should not rely on any such information in making your investment decision.**

**CERTAIN DOCUMENTS INCORPORATED BY REFERENCE**

We have "incorporated by reference" into this prospectus certain information that we file with the SEC. This means that we can disclose important business, financial and other information that is not included in or delivered with this prospectus by referring you to the documents containing this information.

We incorporate by reference the documents listed below and all future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, in each case other than information deemed to be furnished and not filed (unless we specifically state in such filing that such information is to be considered "filed" under the Exchange Act), on or after the date of this prospectus and prior to the completion or termination of the Exchange Offer made pursuant to this prospectus or for so long as we are obligated to make this prospectus available to broker-dealers for resale as described herein:

- our Annual Report on Form 10-K for the year ended December 31, 2017;
- the information specifically incorporated by reference into the Annual Report on Form 10-K for the year ended December 31, 2017 from our definitive proxy statement on Schedule 14A, filed on March 26, 2018; and
- our Current Reports on Form 8-K filed January 11, 2018, January 19, 2018, February 23, 2018, February 26, 2018 and April 2, 2018.

The incorporation by reference of the filings listed above does not extend to any such filings made by Corp and not us or to any information in any filings jointly made by Corp and us regarding Corp or its other subsidiaries, but not regarding us.

All information incorporated by reference is deemed to be part of this prospectus except to the extent that the information is updated or superseded by information filed with the SEC after the date the incorporated information was filed (including later-dated reports listed above) or by the information contained in this prospectus. Any information that we subsequently file with the SEC that is incorporated by reference, as described above, will automatically update and supersede as of the date of such filing any previous information that had been part of this prospectus, or that had been incorporated herein by reference.

You may request a copy of these filings at no cost by writing or contacting us at the following address:

The Office of the Corporate Secretary
PG&E Corporation
77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
Telephone: (415) 973-8200
Facsimile: (415) 973-8719

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus and the documents incorporated by reference contain forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this prospectus. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Company will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. We are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the impact of the Northern California wildfires, including the costs of restoration of service to customers and repairs to the Company facilities, and whether the Company is able to recover such costs through a Catastrophic Event Memorandum Account; the timing and outcome of the wildfire investigations, including into the causes of the wildfires; whether the Company may have liability associated with these fires; if liable for one or more fires, whether the Company would be able to recover all or part of such costs through insurance or through regulatory mechanisms, to the extent insurance is not available or exhausted; and potential liabilities in connection with fines or penalties that could be imposed on the Company if the California Department of Forestry and Fire Protection and the California Public Utilities Commission ("CPUC") or any other law enforcement agency brought an enforcement action and determined that the Company failed to comply with applicable laws and regulations;
- the impact of the Tax Cuts and Jobs Act of 2017 ("Tax Act"), and the timing and outcome of the CPUC decision related to the Company's future filings in connection with the impact of the Tax Act on the Company's rate cases and its implementation plan;
- the Company's ability to efficiently manage capital expenditures and its operating and maintenance expenses within the authorized levels of spending and timely recover its costs through rates, and the extent to which the Company incurs unrecoverable costs that are higher than the forecasts of such costs;
- the timing and outcomes of the 2019 GT&S rate case, TO18 and TO19 rate cases (as such terms are defined in the Company's Annual Report on Form 10-K) and other ratemaking and regulatory proceedings;
- the timing and outcome of the Butte fire litigation, the timing and outcome of any proceeding to recover costs in excess of insurance from customers, if any;
- the effect, if any, that the $8.3 million citations issued by the CPUC Safety and Enforcement Division ("SED") in connection with the Butte fire may have on the Butte fire litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Company;
- whether the CPUC approves the Company's application to establish a Wildfire Expense Memorandum Account ("WEMA") to track wildfire expenses and to preserve the opportunity for the Company to request recovery of wildfire costs in excess of insurance at a future date, and the outcome of any potential request to recover such costs;
- the outcome of the probation and the monitorship imposed by the federal court after the Company's conviction in the federal criminal trial in 2017, the timing and outcomes of the debarment proceeding, the SED's unresolved enforcement matters relating to the Company's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Company's compliance with natural gas- and electric-related laws and regulations, ex parte communications, and the ultimate amount of fines, penalties, and remedial costs that the Company may incur in connection with the outcomes;

- the timing and outcomes of investigations by the U.S. Attorney's Office in San Francisco and the California Attorney General's office related to communications between the Company's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in the Company's ratemaking proceedings;
- the effects on Corp's and the Company's reputations caused by the Company's conviction in the federal criminal trial in 2017, the state and federal investigations of natural gas incidents and the Northern California wildfires, improper communications between the CPUC and the Company, and the Company's ongoing work to remove encroachments from transmission pipeline rights-of-way;
- whether the Company can control its costs within the authorized levels of spending, and successfully implement a streamlined organizational structure and achieve project savings, the extent to which the Company incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;
- whether the Company is able to successfully adapt its business model to significant change that the electric industry is undergoing and the impact such change will have on the natural gas industry;
- the impact of increased costs to comply with natural gas regulations, including the Senate Bill 887 directing Division of Oil, Gas and Geothermal Resources and the California Air Resources Board to develop permanent regulations for gas storage facility operations in California to comply with new safety and reliability measures; the Pipeline and Hazardous Materials Safety Administration rules effective January 18, 2017 regulating gas storage facilities at the federal level; and the CPUC General Order 112-F that went into effect on January 1, 2017, that requires additional expenditures in the areas of gas leak repair, leak survey, high consequences area identification, and operator qualifications, and could impact the Company's ability to timely recover such costs;
- whether the Company and its third-party vendors and contractors are able to protect the Company's operational networks and information technology systems from cyber- and physical attacks, or other internal or external hazards;
- the timing and outcome of the complaint filed by the CPUC and certain other parties with the Federal Energy Regulatory Commission ("FERC") on February 2, 2017 that requests that the Company provide an open and transparent planning process for its capital transmission projects that do not go through the California Independent System Operator's ("CAISO") Transmission Planning Process to allow for greater participation and input from interested parties; and the timing and ultimate outcome of the Ninth Circuit Court of Appeals decision on January 8, 2018, to reverse FERC's decision granting Corp a 50 basis point return on equity incentive adder for continued participation in the CAISO and remanding the case to FERC for further proceedings;
- the amount and timing of additional common stock and debt issuances by Corp, including the dilutive impact of common stock issuances to fund Corp's equity contributions to the Company as the Company incurs charges and costs, including fines, that it cannot recover through rates;
- the outcome of the safety culture order instituting investigation, including its phase two proceeding opened on May 8, 2017, and future legislative or regulatory actions that may be taken, such as requiring the Company to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or implement corporate governance changes;
- the outcome of current and future self-reports, investigations or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Company's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cyber security, environmental laws and regulations; and the outcome of notices of violations in connection with the Yuba City incident;

- the outcomes of the CPUC's data requests and future proposed decisions, including in connection with the Company's SmartMeter™ Upgrade cost-benefit analysis, and of the Company's petitions for modification, including in connection with the installation of new cathodic protection systems in 2018;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Company's known and unknown remediation obligations; and the extent to which the Company is able to recover environmental costs in rates or from other sources;
- the ultimate amount of unrecoverable environmental costs the Company incurs associated with the Company's natural gas compressor station site located near Hinkley, California;
- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect the Company's ability to continue operating Diablo Canyon nuclear power plant ("Diablo Canyon"); whether the Company will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees as a result of its planned retirement by 2024 and 2025;
- the impact of wildfires, droughts, floods, or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Company's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Company, its customers, or third parties on which the Company relies, and the reparation and other costs that the Company may incur in connection with such conditions or events; the impact of the adequacy of the Company's emergency preparedness; whether the Company incurs liability to third parties for property damage or personal injury caused by such events; whether the Company is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Company's insurance coverage is available for these types of claims and sufficient to cover the Company's liability;
- the breakdown or failure of equipment that can cause fires and unplanned outages; and whether the Company will be subject to investigations, penalties, and other costs in connection with such events;
- how the CPUC and the California Air Resource Board implement state environmental laws relating to greenhouse gas, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including whether the Company is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Company is able to timely recover its associated investment costs;
- whether the Company's climate change adaptation strategies are successful;
- the impact that reductions in customer demand for electricity and natural gas have on the Company's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Company is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing the Company's procurement service for community choice aggregators;
- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Company can manage and respond to the volatility of energy commodity prices; the ability of the Company and its counterparties to post or return collateral in connection with price risk management activities; and whether the Company is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- whether, as a result of Westinghouse Electric Company, LLC's ("Westinghouse") Chapter 11 proceeding and its planned purchase by Brookfield Business Partners L.P., the Company will experience issues with nuclear fuel supply, nuclear fuel inventory, and related services and products that Westinghouse supplies, and whether such proceeding will affect the Company's contracts with Westinghouse;
- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Company can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;
- the ability of Corp and the Company to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;
- changes in credit ratings which could, among other things, result in higher borrowing costs and fewer financing options, especially if Corp or the Company were to lose their investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on Corp when it became the Company's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the Company's conviction in the federal criminal trial, and other enforcement matters will impact the Company's ability to make distributions to Corp, and, in turn, Corp's ability to pay dividends;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;
- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the new federal administration; and
- the impact of changes in U.S. Generally Accepted Accounting Principles ("GAAP"), standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and our future financial condition, results of operations and cash flows, you should read the sections titled "Risk Factors" in this prospectus and the documents incorporated by reference in this prospectus.

You should read this prospectus and the documents that we incorporate by reference into this prospectus completely and with the understanding that our actual future results could be materially different from what we expect when making the forward-looking statements. We qualify all our forward-looking statements by these cautionary statements. These forward-looking statements speak only as of the date of this prospectus or the date of the document incorporated by reference. Except as required by applicable laws or regulations, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Additionally, Corp and the Company routinely provide links to the Company's principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on this website is not part of this prospectus or any other report that Corp or the Company files with, or furnishes to, the SEC. Corp and the Company are providing the address to this website solely for the information of investors and do not intend the address to be an active link. Corp and the Company also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "News & Events: Events & Presentations" tab, in order to publicly disseminate such information.

## SUMMARY

*This summary highlights selected information about us and the Exchange Offer and is therefore qualified in its entirety by the more detailed information appearing elsewhere, or incorporated by reference, in this prospectus. It may not contain all the information that may be important to you. We urge you to read carefully this entire prospectus and the other documents to which it refers to understand fully the terms of the Exchange Notes and the Exchange Offer.*

### Our Company

We are one of the largest combination natural gas and electric utilities in the United States. We were incorporated in California in 1905 and are a subsidiary of PG&E Corporation. We provide natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California. We generate revenues mainly through the sale and delivery of electricity and natural gas to customers. The principal executive offices of PG&E Corporation and Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and the telephone number of Pacific Gas and Electric Company is (415) 973-7000.

This prospectus contains summaries believed to be accurate with respect to certain documents, but reference is made to the actual documents themselves for complete information. All such summaries are qualified in their entirety by such reference. To obtain timely delivery, you must request the information incorporated by reference herein no later than five business days before the Expiration Date (as defined below) of the Exchange Offer. We will, upon request, provide without charge to each person to whom this prospectus is delivered a copy of any or all of the documents incorporated or deemed to be incorporated by reference into this prospectus (other than exhibits to such documents, unless such exhibits are specifically incorporated by reference into this prospectus). See “Where You Can Find More Information”.

**SUMMARY OF THE EXCHANGE OFFER**

*On November 29, 2017, we completed a private offering of $500,000,000 aggregate principal amount of Floating Rate Senior Notes due November 28, 2018, $1,150,000,000 aggregate principal amount of 3.30% Senior Notes due December 1, 2027 and $850,000,000 aggregate principal amount of 3.95% Senior Notes due December 1, 2047, which we collectively refer to as the "Restricted Notes". As part of that offering, we entered into a registration rights agreement with the initial purchasers of those Restricted Notes in which we agreed to use our commercially reasonable efforts to complete an exchange offer for such Restricted Notes in compliance with applicable securities laws. See "The Exchange Offer-Purpose of the Exchange Offer".*

*The following is a brief summary of certain terms of the Exchange Offer and the principal terms of the Exchange Notes. It may not contain all the information that is important to you. For additional information regarding the Exchange Offer and the Exchange Notes, see "The Exchange Offer" and "Description of the Exchange Notes".*

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| **Issuer** | Pacific Gas and Electric Company. |
| **Restricted Notes** | $500,000,000 in aggregate principal amount of Floating Rate Senior Notes due November 28, 2018. |
| | $1,150,000,000 in aggregate principal amount of 3.30% Senior Notes due December 1, 2027. |
| | $850,000,000 in aggregate principal amount of 3.95% Senior Notes due December 1, 2047. |
| **Exchange Notes** | $500,000,000 in aggregate principal amount of Floating Rate Senior Notes due November 28, 2018. |
| | $1,150,000,000 in aggregate principal amount of 3.30% Senior Notes due December 1, 2027. |
| | $850,000,000 in aggregate principal amount of 3.95% Senior Notes due December 1, 2047. |
| | The Exchange Notes have been registered under the Securities Act. |
| | The form and terms of the Exchange Notes are identical in all material respects to those of the Restricted Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the Restricted Notes do not apply to the Exchange Notes. |
| | In addition, the Exchange Notes bear different CUSIP and ISIN numbers than the corresponding series of Restricted Notes. |
| **The Exchange Offer** | We are offering to exchange up to $500,000,000 aggregate principal amount of the 2018 Restricted Notes, $1,150,000,000 aggregate principal amount of the 2027 Restricted Notes and $850,000,000 aggregate principal amount of the 2047 Restricted Notes for a like aggregate principal amount of the 2018 Exchange Notes, 2027 Exchange Notes and 2047 Exchange Notes, respectively, to satisfy certain of our obligations under the registration rights agreement that we entered into when the Restricted Notes were issued in reliance upon exemptions from registration under the Securities Act. |

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| | The Restricted Notes may only be tendered in minimum denominations of $100,000 in principal amount or in integral multiples of $1,000 in excess thereof. See "The Exchange Offer-Terms of the Exchange Offer".<br><br>In order to exchange the Restricted Notes, you must follow the required procedures and we must accept the Restricted Notes for exchange. We will exchange all Restricted Notes validly tendered and not validly withdrawn prior to the Expiration Date (as defined below) of the Exchange Offer. See "The Exchange Offer". |
| **Expiration Date; Tenders** | The Exchange Offer will expire at 5:00 p.m., New York City time, on May 14, 2018, unless extended by us (such date and time, as they may be extended, the "Expiration Date"). By tendering your Restricted Notes, you represent to us that:<br><br>● any Exchange Notes to be received by you will be acquired in the ordinary course of your business;<br><br>● you are not participating and have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes;<br><br>● you are not an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours; and<br><br>● if you are a broker-dealer that will receive Exchange Notes for your own account in exchange for Restricted Notes that were acquired as a result of market-making or other trading activities, you will deliver a prospectus (or, to the extent permitted by law, make available a prospectus to purchasers) in connection with any resale of such Exchange Notes. For further information regarding resales of the Exchange Notes by participating broker-dealers, see the discussion under the caption "Plan of Distribution". |
| **Withdrawal** | You may withdraw any Restricted Notes tendered in the Exchange Offer at any time prior to the Expiration Date. See "The Exchange Offer-Withdrawal Rights". |
| **Conditions to the Exchange Offer** | The Exchange Offer is subject to customary conditions, which we may waive. The Exchange Offer is not conditioned upon the tender of any minimum principal amount of outstanding Restricted Notes. See "The Exchange Offer-Conditions to the Exchange Offer". |
| **Procedures for Tendering Restricted Notes** | You must do the following on or prior to the expiration or termination of the Exchange Offer to participate in the Exchange Offer:<br><br>● tender your Restricted Notes by sending the certificates for your Restricted Notes, in proper form for transfer, a properly completed and duly executed letter of transmittal, with any required signature guarantees, and all other documents required by the letter of transmittal, to The Bank of New York Mellon Trust Company, N.A., as Exchange Agent, at one of the addresses listed below under the caption "The Exchange Offer-Exchange Agent"; or |

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| | ● tender your Restricted Notes by using the book-entry transfer procedures described below and sending a properly completed and duly executed letter of transmittal, with any required signature guarantees, or causing to be delivered an agent's message instead of the letter of transmittal, to the Exchange Agent. In order for a book-entry transfer to constitute a valid tender of your Restricted Notes in the Exchange Offer, The Bank of New York Mellon Trust Company, N.A., as Exchange Agent, must receive a confirmation of book-entry transfer of your Restricted Notes into the Exchange Agent's account at The Depository Trust Company ("DTC") prior to the expiration or termination of the Exchange Offer. For more information regarding the use of book-entry transfer procedures, including a description of the required agent's message, see the discussion below under the caption "The Exchange Offer-Book-Entry Transfers". |
| | For more information on the procedures for tendering the Restricted Notes, see the discussion under the caption "The Exchange Offer-Procedures for Tendering Restricted Notes". |
| **Special Procedures for Beneficial Owners** | If you are a beneficial owner whose Restricted Notes are registered in the name of the broker, dealer, commercial bank, trust company or other nominee, and you wish to tender your Restricted Notes in the Exchange Offer, you should promptly contact the person in whose name the Restricted Notes are registered and instruct that person to tender on your behalf. Any registered holder that is a participant in DTC's book-entry transfer facility system may make book-entry delivery of the Restricted Notes by causing DTC to transfer the Restricted Notes into the exchange agent's account. If you wish to tender your Restricted Notes in the Exchange Offer on your own behalf, prior to completing and executing the letter of transmittal and delivering your Restricted Notes, you must either make appropriate arrangements to register ownership of the Restricted Notes in your name with DTC or obtain a properly completed note power from the person in whose name the Restricted Notes are registered. |
| **Use of Proceeds** | We will not receive any cash proceeds from the Exchange Offer. |
| **Exchange Agent** | The Bank of New York Mellon Trust Company, N.A., is the "Exchange Agent" for the Exchange Offer. You can find the address, telephone number and e-mail address of the Exchange Agent below under the caption "The Exchange Offer-Exchange Agent". The Bank of New York Mellon Trust Company, N.A. is also the trustee under the Indenture governing the Restricted Notes and Exchange Notes. |
| **Resales** | Based on interpretations by the SEC staff, as detailed in a series of no-action letters issued to third parties, we believe that the Exchange Notes issued in the Exchange Offer pursuant to this prospectus may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery requirements of the Securities Act, provided that: |

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| | ● any Exchange Notes to be received by you will be acquired in the ordinary course of your business;<br>● you are not participating and have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes; and<br>● you are not an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours.<br>We base our belief on interpretations by the SEC staff in no-action letters issued to other issuers making exchange offers similar to ours. We cannot guarantee the SEC would make a similar decision about our Exchange Offer. If our belief is wrong, you could incur liability under the Securities Act. We will not indemnify or otherwise protect you against any loss incurred as a result of this liability under the Securities Act.<br>If you are an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours or are participating or have an arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes:<br>● you cannot rely on the applicable interpretations of the staff of the SEC;<br>● you will not be entitled to participate in the Exchange Offer; and<br>● you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction of the Exchange Notes.<br>See the discussion below under the caption "The Exchange Offer-Consequences of Exchanging or Failing to Exchange Restricted Notes" for more information. |
| **Broker-Dealer** | Each broker or dealer that receives the Exchange Notes for its own account in exchange for the Restricted Notes that were acquired as a result of market-making or other trading activities must acknowledge that it will comply with the registration and prospectus delivery requirements of the Securities Act in connection with any offer to resell or other transfer of the Exchange Notes issued in the Exchange Offer, including the delivery of a prospectus that contains information with respect to any selling holder required by the Securities Act in connection with any resale of the Exchange Notes.<br>Furthermore, any broker-dealer that acquired any of its Restricted Notes directly from us:<br>● may not rely on the applicable interpretation of the SEC staff's position contained in Exxon Capital Holdings Corp., SEC no-action letter (April 13, 1988), Morgan, Stanley & Co. Inc., SEC no-action letter (June 5, 1991) and Shearman & Sterling, SEC no-action letter (July 2, 1993); and |

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| | ● must also be named as a selling noteholder in connection with the registration and prospectus delivery requirements of the Securities Act relating to any resale transaction.<br><br>This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the Exchange Notes received in exchange for the Restricted Notes where such Restricted Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. Under the registration rights agreement, we have agreed to make available a prospectus in conformity in all material respects with the requirements of the Securities Act and the Trust Indenture Act of 1939, as amended, to any participating broker-dealer for use in connection with any resale of any Exchange Notes acquired in the Exchange Offer for the period beginning when the Exchange Notes are first issued in the Exchange Offer and ending upon the earlier of the expiration of the 30th day after the Exchange Offer has been completed or such time as such broker-dealers no longer own any Restricted Notes. See "Plan of Distribution". |
| **Registration Rights Agreement** | When we issued the Restricted Notes on November 29, 2017, we entered into a registration rights agreement with the initial purchasers of the Restricted Notes, pursuant to which we agreed, for the benefit of the holders of the Restricted Notes, at our cost, to use commercially reasonable efforts to:<br><br>● file a registration statement (the "Exchange Offer Registration Statement") with respect to a registered offer to exchange the Restricted Notes for the Exchange Notes having terms substantially identical to the Restricted Notes being exchanged, except that the Exchange Notes will not contain transfer restrictions or provisions regarding the additional interest in case of a Registration Default (as defined below);<br><br>● cause the Exchange Offer Registration Statement to become effective under the Securities Act;<br><br>● complete the Exchange Offer not later than the 365th day following the date of the registration rights agreement; and<br><br>● have the Exchange Offer Registration Statement remain effective until 30 days after the last Exchange Date for use by one or more participating broker-dealers.<br><br>If we do not complete the Exchange Offer on or prior to November 29, 2018, or if we fail to meet certain other conditions described in the registration rights agreement, the interest rate borne by the affected series of Restricted Notes will increase at a rate of 0.25% per annum for the first 90-day period immediately following the occurrence of the Registration Default with respect to such series, increasing by an additional 0.25% per annum with respect to each subsequent 90-day period up to a maximum of additional interest of 0.50% per annum in the aggregate for the affected series, from and including the date on which such Registration Default occurred to, but excluding, the date on which all Registration Defaults with respect to such series have been cured. |

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| | Under some circumstances set forth in the registration rights agreement, holders of the Restricted Notes, including holders who are not permitted to participate in the Exchange Offer, may require us to file, and cause to become effective, a shelf registration statement covering resales of the Restricted Notes by these holders.<br><br>A copy of the registration rights agreement is incorporated by reference as an exhibit to the registration statement of which this prospectus forms a part. See "The Exchange Offer-Purpose of the Exchange Offer". |
| **Consequences of Failure to Exchange** | Restricted Notes that are not tendered or that are tendered but not accepted will, following the completion of the Exchange Offer, be returned to the tendering holder, remain outstanding and continue to be subject to their existing terms. See "Risk Factors" and "The Exchange Offer-Terms of the Exchange Offer". Following the completion of the Exchange Offer, we will have no obligation to exchange Restricted Notes for Exchange Notes.<br><br>The trading market for Restricted Notes not exchanged in the Exchange Offer may be more limited than it is at present. Therefore, if your Restricted Notes are not tendered and accepted in the Exchange Offer, it may become more difficult for you to sell or transfer your unexchanged Restricted Notes. |
| **Regulatory Requirements** | We do not believe that the receipt of any material federal or state regulatory approval will be necessary in connection with the Exchange Offer, other than the notice of effectiveness under the Securities Act of the registration statement pursuant to which the Exchange Offer is being made. |
| **Material Tax Considerations** | The exchange of Restricted Notes for Exchange Notes pursuant to the Exchange Offer generally will not be a taxable event for U.S. federal income tax purposes. You should consult your own tax advisor to determine the U.S. federal, state and other tax consequences of the exchange of the Restricted Notes for the Exchange Notes. See "Material U.S. Federal Income Tax Consequences". |

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| **Accounting Treatment** | We will not recognize any gain or loss for accounting purposes upon the completion of the Exchange Offer. The expenses of the Exchange Offer that we pay will increase our deferred financing costs in accordance with U.S. GAAP. See "The Exchange Offer-Accounting Treatment". |
| **Risk Factors** | See "Risk Factors" for a discussion of factors that should be considered before exchanging any series of Restricted Notes in the Exchange Offer. |

## SUMMARY DESCRIPTION OF THE EXCHANGE NOTES

*The summary below describes the principal terms of the Exchange Notes. The "Description of the Exchange Notes" section of this prospectus contains a more detailed description of the terms of the Exchange Notes. As used in this section, the terms "we," "us" and "our" refer to Pacific Gas and Electric Company, and not to any of its subsidiaries.*

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| **Issuer** | Pacific Gas and Electric Company. |
| **Exchange Notes Offered** | $500,000,000 in aggregate principal amount of Floating Rate Senior Notes due November 28, 2018.<br><br>$1,150,000,000 in aggregate principal amount of 3.30% Senior Notes due December 1, 2027.<br><br>$850,000,000 in aggregate principal amount of 3.95% Senior Notes due December 1, 2047. |
| **Maturity Dates** | The 2018 Exchange Notes will mature on November 28, 2018.<br><br>The 2027 Exchange Notes will mature on December 1, 2027.<br><br>The 2047 Exchange Notes will mature on December 1, 2047. |
| **Interest** | The 2018 Exchange Notes will accrue interest at a per annum rate equal to three-month LIBOR for U.S. dollars plus 0.23% (or 23 basis points), reset quarterly as more fully described herein, and will be payable quarterly in arrears on May 28, 2018, August 28, 2018 and November 28, 2018. See the discussion below under the caption "Description of the Exchange Notes-Interest-Rate of Interest on the 2018 Notes" and "Description of the Exchange Notes-Interest-Interest Rate Determination on the 2018 Notes" for more information.<br><br>The 2027 Exchange Notes will accrue interest at 3.30% per annum, payable semi-annually in arrears on June 1 and December 1 of each year, beginning on June 1, 2018.<br><br>The 2047 Exchange Notes will accrue interest at 3.95% per annum, payable semi-annually in arrears on June 1 and December 1 of each year, beginning on June 1, 2018.<br><br>In the case of each series of Exchange Notes, interest will accrue from the most recent date to which interest on the corresponding series of Restricted Notes has been paid, or if no interest has been paid with respect to such series, from November 29, 2017. No interest will be paid on any series of Restricted Notes that is tendered and accepted for exchange following their acceptance for exchange with respect to such series. |
| **Ranking** | The Exchange Notes will be our direct, unsecured and unsubordinated obligations and will rank equally with all our other existing and future unsecured and unsubordinated obligations. The Exchange Notes will be effectively subordinated to all our secured debt. As of December 31, 2017, we had approximately $17.4 billion of long-term debt outstanding (net of current portion), none of which was secured. |
| **Optional Redemption** | The 2018 Exchange Notes will not be redeemable prior to maturity. |

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| | We may redeem the 2027 Exchange Notes, in whole or in part, at any time or from time to time, prior to September 1, 2027 (the date that is three months prior to the maturity date of the 2027 Exchange Notes) and we may redeem the 2047 Exchange Notes, in whole or in part, at any time or from time to time, prior to June 1, 2047 (the date that is six months prior to the maturity date of the 2047 Exchange Notes), in each case, at a specified make-whole premium described under the heading "Description of Exchange Notes- Optional Redemption for Fixed Rate Notes," plus accrued and unpaid interest thereon to, but excluding, the redemption date.<br><br>On or after September 1, 2027 with respect to the 2027 Exchange Notes (the date that is three months prior to the maturity date of the 2027 Exchange Notes) and on or after June 1, 2047 with respect to the 2047 Exchange Notes (the date that is six months prior to the maturity date of the 2047 Exchange Notes), such series of Exchange Notes will be redeemable, in whole or in part, at our option at any time and from time to time, at a redemption price equal to 100% of the principal amount of the Fixed Rate Exchange Notes to be redeemed, plus accrued and unpaid interest thereon to, but excluding, the redemption date. |
| **Certain Covenants** | The indenture that will govern the Exchange Notes contains covenants limiting our ability and our subsidiaries' ability to:<br><br>● incur or assume debt secured by certain property,<br><br>● enter into certain sale and leaseback transactions, and<br><br>● consolidate with or merge with or into any other person or convey, otherwise transfer or lease all or substantially all our principal property.<br><br>However, each of these covenants is subject to certain exceptions. You should read "Description of Exchange Notes-Covenants" for a description of these covenants. |
| **Absence of Public Trading Market** | We do not intend to list any series of Exchange Notes on any securities exchange nor will any series of Exchange Notes be quoted on any automated dealer quotation system. If issued, the Exchange Notes generally will be freely transferable but will also be new securities for which there will not initially be a market. We cannot assure you that any trading market for the Exchange Notes of any series will develop upon completion of the Exchange Offer or, if such a market does develop, that such market will be maintained or as to the liquidity of any market. Accordingly, we cannot provide assurance as to the development or liquidity of any market for any series of Exchange Notes. See "Risk Factors-Your ability to transfer the Exchange Notes may be limited by the absence of an active trading market, and an active trading market may not develop for the Exchange Notes". |
| **Governing Law** | The indenture is, and the Exchange Notes will be, governed by, and construed in accordance with, the laws of the State of New York. |
| **Trustee** | The Bank of New York Mellon Trust Company, N.A. |

## RISK FACTORS

*Investing in our securities involves risk. Please see risk factors described in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and other reports filed by the Company with the SEC, which are incorporated by reference in this prospectus, as updated or supplemented herein. Before deciding whether to participate in the Exchange Offer, you should carefully consider these risks as well as other information contained or incorporated by reference in this prospectus. The risks and uncertainties described are not the only ones facing us. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations, financial results and the value of our securities.*

***If the Company were to be found liable for one or more of the Northern California wildfires, Corp and the Company would likely require additional financing, which may include secured indebtedness to which the Exchange Notes offered hereby would be effectively subordinated.***

If the Company were to be found liable for one or more of the Northern California wildfires, Corp and the Company would likely require additional financing, which may be substantial, to satisfy obligations as they become due, including claims for property damages, interest and attorneys' fees, fire suppression costs, personal injury damages, and other damages. Any such financing could take a number of forms, including indebtedness incurred by the Company secured by liens on the Company's assets, in which case the Exchange Notes offered hereby would be effectively subordinated to such indebtedness to the extent of the value of such collateral. Such new financing could also require amortization, mandatory redemption or have near-term maturities, such that substantial cash outflows could occur prior to the maturity of the Exchange Notes offered hereby. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy existing financial obligations, including those relating to the Exchange Notes offered hereby.

***Our indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under our outstanding indebtedness and the Exchange Notes.***

As of December 31, 2017, we had approximately $17.4 billion of long-term debt outstanding (net of current portion). Our indebtedness could have important consequences for you. For example, it could:

- make it difficult for us to satisfy our obligations with respect to the Exchange Notes;
- increase our vulnerability to general adverse economic and industry conditions;
- require us to dedicate a portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of cash flow to fund working capital, capital expenditures, acquisitions and investments and other general corporate purposes;
- make it difficult for us to optimally capitalize and manage the cash flow for our businesses;
- limit our flexibility in planning for, or reacting to, changes in our businesses and the markets in which we operate;
- place us at a competitive disadvantage compared to our competitors that have less debt; and
- limit our ability to borrow additional funds or to borrow funds at rates or on other terms we find acceptable.

In addition, the agreements governing our indebtedness, including our credit facility agreements, impose operating and financial restrictions on our activities. For example, Corp's and the Company's respective credit agreements contain financial covenants that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%.

We may incur additional indebtedness in the future. If new debt is added to current debt levels, the risks described above could intensify. Furthermore, if future debt financing is not available to us when required or is not available on acceptable terms, we may be unable to grow our business, take advantage of business opportunities, respond to competitive pressures or refinance maturing debt, any of which could have a material adverse effect on our operating results and financial condition.

***Any Restricted Notes that are not exchanged will continue to be restricted securities and, following completion of the Exchange Offer, will have a less liquid trading market.***

Restricted Notes that you do not tender or we do not accept will, following the Exchange Offer, continue to be subject to the restrictions on transfer applicable to the Restricted Notes. The restrictions on transfer of your Restricted Notes arise because we issued the Restricted Notes under exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws. In general, you may only offer or sell the Restricted Notes if they are registered under the Securities Act and applicable state securities laws, or offered and sold under an exemption from these requirements. We do not plan to register the Restricted Notes under the Securities Act. For further information regarding the consequences of tendering your Restricted Notes in the Exchange Offer, see the discussion below under the caption "The Exchange Offer-Consequences of Exchanging or Failing to Exchange Restricted Notes".

Because we anticipate that most holders of Restricted Notes will elect to exchange their Restricted Notes, we expect that the liquidity of the market for any Restricted Notes remaining after the completion of the Exchange Offer will be substantially limited. Any Restricted Notes tendered and exchanged in the Exchange Offer will reduce the aggregate principal amount of the Restricted Notes outstanding. Following the Exchange Offer, if you do not tender your Restricted Notes, you generally will not have any further registration rights, and your Restricted Notes will continue to be subject to certain transfer restrictions. Accordingly, the liquidity of the market for the Restricted Notes could be adversely affected by the Exchange Offer.

***Your ability to transfer the Exchange Notes may be limited by the absence of an active trading market, and an active trading market may not develop for the Exchange Notes.***

The Exchange Notes will be a new issue of securities for which there is no established trading market. We do not intend to list the Exchange Notes on any national securities exchange or include the Exchange Notes in any automated quotation system. Therefore, an active market for the Exchange Notes may not develop or be maintained, which would adversely affect the market price and liquidity of the Exchange Notes. In that case, the noteholders may not be able to sell their Exchange Notes at a particular time or at a favorable price, if at all.

Even if an active trading market for the Exchange Notes does develop, there is no guarantee that it will continue. In addition, subsequent to their initial issuance, the Exchange Notes may trade at a discount, depending upon prevailing interest rates, the market for similar notes, our performance and other factors.

***The ability of a broker-dealer to transfer the Exchange Notes may be restricted.***

A broker-dealer that acquired the Restricted Notes for its own account as a result of market-making activities or other trading activities must comply with the prospectus delivery requirements of the Securities Act in connection with any resale of the Exchange Notes. Our obligation to make this prospectus available to broker-dealers is limited. Consequently, we cannot guarantee that a proper prospectus will be available to broker-dealers wishing to resell their Exchange Notes.

***You must comply with the Exchange Offer procedures in order to receive new, freely tradable Exchange Notes.***

Delivery of the Exchange Notes in exchange for the Restricted Notes tendered and accepted for exchange pursuant to the Exchange Offer will be made only after timely receipt by the Exchange Agent of the following:

- certificates for Restricted Notes or a book-entry confirmation of a book-entry transfer of Restricted Notes into the Exchange Agent's account at DTC, New York, New York as depository, including an agent's message (as defined herein) if the tendering holder does not deliver a letter of transmittal;

- a completed and signed letter of transmittal (or facsimile thereof), with any required signature guarantees, or an agent's message in lieu of the letter of transmittal; and

- any other documents required by the letter of transmittal.

Therefore, holders of Restricted Notes who would like to tender Restricted Notes in exchange for Exchange Notes should allow enough time for the Restricted Notes to be delivered on time. We are not required to notify you of defects or irregularities in tenders of the Restricted Notes for exchange. The Restricted Notes that are not tendered or that are tendered but we do not accept for exchange will, following consummation of the Exchange Offer, continue to be subject to the existing transfer restrictions under the Securities Act and, upon consummation of the Exchange Offer, certain registration and other rights under the registration rights agreement will terminate. See “The Exchange Offer-Procedures for Tendering Restricted Notes” and “The Exchange Offer-Consequences of Exchanging or Failing to Exchange Restricted Notes”.

***Some holders who exchange their Restricted Notes may be deemed to be underwriters, and these holders will be required to comply with the registration and prospectus delivery requirements in connection with any resale transaction.***

If you exchange your Restricted Notes in the Exchange Offer for the purpose of participating in a distribution of the Exchange Notes, you may be deemed to have received restricted securities and, if so, will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

***Uncertainty relating to the LIBOR calculation process and potential phasing out of LIBOR after 2021 may adversely affect the value of the 2018 Exchange Notes.***

Regulators and law enforcement agencies in the United Kingdom and elsewhere are conducting civil and criminal investigations into whether the banks that contribute to the British Bankers’ Association (“BBA”) in connection with the calculation of daily LIBOR may have been under-reporting or otherwise manipulating or attempting to manipulate LIBOR. A number of BBA member banks have entered into settlements with their regulators and law enforcement agencies with respect to this alleged manipulation of LIBOR.

Actions by the BBA, regulators or law enforcement agencies may result in changes to the manner in which LIBOR is determined or the establishment of alternative reference rates. For example, on July 27, 2017, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. At this time, it is not possible to predict the effect of any such changes, any establishment of alternative reference rates or any other reforms to LIBOR that may be enacted in the United Kingdom or elsewhere, but it is possible that LIBOR will be discontinued or modified by 2021. It is not possible to predict the effect that this announcement or any such discontinuance will have on the three-month U.S. dollar LIBOR rate or the 2018 Exchange Notes. Uncertainty as to the nature of such potential changes, alternative reference rates or other reforms may adversely affect the trading market for LIBOR-based securities, the value of the 2018 Exchange Notes and the level of interest payments on the 2018 Exchange Notes.

**RATIO OF EARNINGS TO FIXED CHARGES**

The following table shows the ratios of earnings to fixed charges of Pacific Gas and Electric Company for the periods indicated.

| | Year Ended December 31,(1) | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2014 | 2013 |
| Ratio of earnings to fixed charges | 2.35 | 2.04 | 1.67 | 2.55 | 2.23 |

(1) Refer to Exhibit 12.01 of our Annual Report on Form 10-K for the year ended December 31, 2017 for the computation of these ratios.

## USE OF PROCEEDS

The Exchange Offer is intended to satisfy our obligations under the registration rights agreement entered into in connection with the issuance of the Restricted Notes. We will not receive any cash proceeds from the Exchange Offer. The Restricted Notes exchanged in connection with the Exchange Offer will be retired and cancelled and will not be reissued. Accordingly, issuance of the Exchange Notes will not result in any change in our indebtedness other than to the extent that we incur any indebtedness in connection with the payment of expenses to be incurred in connection with the Exchange Offer, including the fees and expenses of the exchange agent and accounting and legal fees.

**SELECTED HISTORICAL CONSOLIDATED FINANCIAL INFORMATION**

The selected historical consolidated historical financial information presented below for the years ended December 31, 2017, 2016, 2015, 2014 and 2013, and at year-end on December 31, 2017, 2016, 2015, 2014 and 2013, are derived from our consolidated financial statements. You should read this table along with our Annual Report on Form 10-K for our fiscal year ended December 31, 2017.

| (in millions, except per share amounts) | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year Ended December 31,** | | | | | |
| Operating revenues | $ 17,138 | $ 17,667 | $ 16,833 | $ 17,088 | $ 15,593 |
| Operating income | 2,900 | 2,181 | 1,511 | 2,452 | 1,790 |
| Income available for common stock | 1,677 | 1,388 | 848 | 1,419 | 852 |
| **At Year-End on December 31,** | | | | | |
| Total assets | 67,884 | 68,374 | 63,037 | 59,964 | 55,137 |
| Long-term debt (excluding current portion) | 17,403 | 15,872 | 15,577 | 14,799 | 12,805 |
| Capital lease obligations (excluding current portion) [1] | 18 | 31 | 49 | 69 | 90 |

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[1] The capital lease obligations amounts are included in Noncurrent Liabilities - Other in Corp's and the Company's Consolidated Balance Sheets.

## THE EXCHANGE OFFER

**Purpose of the Exchange Offer**

When we issued the Restricted Notes on November 29, 2017, we entered into a registration rights agreement with the initial purchasers of the Restricted Notes, pursuant to which we agreed, for the benefit of the holders of the Restricted Notes, at our cost, to use commercially reasonable efforts to:

- file a registration statement (the "Exchange Offer Registration Statement") with respect to a registered offer to exchange the Restricted Notes for the Exchange Notes having terms substantially identical to the Restricted Notes being exchanged, except that the Exchange Notes will not contain transfer restrictions or provisions regarding the additional interest in case of a Registration Default (as defined below);
- cause the Exchange Offer Registration Statement to become effective under the Securities Act;
- complete the Exchange Offer not later than the 365th day following the date of the registration rights agreement; and
- have the Exchange Offer Registration Statement remain effective until 30 days after the last Exchange Date for use by one or more participating broker-dealers.

If we do not complete the Exchange Offer on or prior to November 29, 2018 or if we fail to meet certain other conditions described in the registration rights agreement, the interest rate borne by the affected series of Restricted Notes will increase at a rate of 0.25% per annum for the first 90-day period immediately following the occurrence of the Registration Default with respect to such series, increasing by an additional 0.25% per annum with respect to each subsequent 90-day period up to a maximum of additional interest of 0.50% per annum in the aggregate for the affected series, from and including the date on which such Registration Default occurred to, but excluding, the date on which all Registration Defaults with respect to such series have been cured.

Under some circumstances set forth in the registration rights agreement, holders of the Restricted Notes, including holders who are not permitted to participate in the Exchange Offer, may require us to file, and cause to become effective, a shelf registration statement covering resales of the Restricted Notes by these holders.

We are making the Exchange Offer in reliance on the position of the SEC as described in previous no-action letters issued to third parties, including in Exxon Capital Holdings Corporation (April 13, 1988), Morgan Stanley & Co., Inc. (June 5, 1991), Shearman & Sterling (July 2, 1993) and similar no-action letters. However, we have not sought our own no-action letter. Based upon these interpretations by the SEC, we believe that a holder who exchanges Restricted Notes for Exchange Notes in the Exchange Offer generally may offer the Exchange Notes for resale, sell the Exchange Notes and otherwise transfer the Exchange Notes without further registration under the Securities Act and without delivery of a prospectus that satisfies the requirements of Section 10 of the Securities Act. The preceding sentence does not apply, however, to a holder who is our "affiliate" within the meaning of Rule 405 of the Securities Act. We also believe that a holder may offer, sell or transfer the Exchange Notes only if the holder acknowledges that the holder is acquiring the Exchange Notes in the ordinary course of its business and is not participating, does not intend to participate and has no arrangement or understanding with any person to participate in a "distribution", as defined in the Securities Act, of the Exchange Notes. We have not entered into any arrangement or understanding with any person who will receive Exchange Notes in the Exchange Offer to distribute such Exchange Notes following completion of the Exchange Offer, and, to the best of our information and belief, we are not aware of any person that will participate in the Exchange Offer with a view to distribute the Exchange Notes. A holder who exchanges Restricted Notes for Exchange Notes in the Exchange Offer for the purpose of distributing such Exchange Notes cannot rely on the interpretations of the staff of the SEC in the aforementioned no-action letters, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any secondary resale of the Exchange Notes and must be identified as an underwriter in the prospectus.

Each broker-dealer that receives the Exchange Notes for its own account in exchange for the Restricted Notes, where the Restricted Notes were acquired by it as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the Exchange Notes and that it has not entered into any agreement or understanding with us or any of our "affiliates", as defined in Rule 405 under the Securities Act, to participate in a "distribution", as defined under the Securities Act, of the Exchange Notes. By so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. See "Plan of Distribution".

The summary herein of certain provisions of the registration rights agreement does not purport to be complete, and is qualified in its entirety by reference to, all the provisions of the registration rights agreement, a copy of which is incorporated by reference as an exhibit to the registration statement of which this prospectus forms a part.

**Terms of the Exchange Offer**

We are offering holders of the Restricted Notes the opportunity to exchange their Restricted Notes for Exchange Notes in the manner described in this prospectus and the accompanying Letter of Transmittal.

Subject to the terms and the satisfaction or waiver of the conditions detailed in this prospectus, we will accept for exchange all Restricted Notes which are validly tendered on or prior to the Expiration Date and not validly withdrawn as permitted below. The Exchange Offer will expire at 5:00 p.m., New York City time, on May 14, 2018, unless extended by us (such date and time, as they may be extended, the "Expiration Date").

The terms of the Exchange Notes will be substantially identical to the terms of the corresponding series of the Restricted Notes, except that the Exchange Notes will not contain terms with respect to additional interest for failure to fulfill certain of our obligations under the registration rights agreement and transfer restrictions. The Exchange Notes will evidence the same debt as the Restricted Notes of such series. The Exchange Notes will be issued under and entitled to the benefits of the same indenture under which the outstanding Restricted Notes were issued. The Exchange Notes and the corresponding series of the Restricted Notes will constitute a single class for all purposes under the indenture governing the notes. For a description of the indenture governing the notes, please see "Description of the Exchange Notes".

The Exchange Offer is not conditioned upon any minimum aggregate principal amount of any series of Restricted Notes being tendered for exchange. Any Restricted Notes not tendered will remain outstanding and continue to accrue interest but will not retain any rights under the registration rights agreement, except as otherwise specified therein.

As of the date of this prospectus, $500,000,000 aggregate principal amount of the 2018 Restricted Notes, $1,150,000,000 aggregate principal amount of the 2027 Restricted Notes and $850,000,000 aggregate principal amount of the 2047 Restricted Notes are outstanding. This prospectus, together with the Letter of Transmittal, is first being sent on or about the date hereof to all holders of Restricted Notes known to us.

We expressly reserve the right, at any time prior to the expiration of the Exchange Offer, to extend the period of time during which the Exchange Offer is open and delay acceptance for exchange of any Restricted Notes, by giving oral or written notice of such extension to holders thereof as described below. During any such extension, all the Restricted Notes previously tendered will remain subject to the Exchange Offer and may be accepted for exchange by us. Any Restricted Notes not accepted for exchange for any reason will be returned without expense to an account maintained with DTC promptly upon expiration or termination of the Exchange Offer.

The Restricted Notes tendered in the Exchange Offer must be in denominations of principal amount of $100,000 and any integral multiple of $1,000 in excess thereof.

We expressly reserve the right to amend or terminate the Exchange Offer, and not to accept for exchange any Restricted Notes, upon the occurrence of any of the conditions of the Exchange Offer specified under "-Conditions to the Exchange Offer". We will give oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the Restricted Notes as promptly as practicable. Such notice, in the case of any extension, will be issued by means of a press release or other public announcement no later than 9:00 AM, New York City time, on the next business day after the previously scheduled Expiration Date.

**Procedures for Tendering Restricted Notes**

The tender to us of Restricted Notes by you as set forth below and our acceptance of the Restricted Notes will constitute a binding agreement between us and you upon the terms and subject to the conditions set forth in this prospectus and in the accompanying Letter of Transmittal. Except as set forth below, to tender Restricted Notes for exchange pursuant to the Exchange Offer, you must transmit a properly completed and duly executed Letter of Transmittal, including all other documents required by such Letter of Transmittal or, in the case of a book-entry transfer, an agent's message in lieu of such Letter of Transmittal, to The Bank of New York Mellon Trust Company, N.A., as Exchange Agent, at the address set forth below under "-Exchange Agent" on or prior to the Expiration Date. In addition, either:

- certificates for such Restricted Notes must be received by the Exchange Agent along with the Letter of Transmittal; or

- a timely confirmation of a book-entry transfer (a "book-entry confirmation") of such Restricted Notes, if such procedure is available, into the Exchange Agent's account at DTC pursuant to the procedure for book-entry transfer must be received by the Exchange Agent, prior to the Expiration Date, with the Letter of Transmittal or an agent's message in lieu of such Letter of Transmittal.

The term "agent's message" means a message, transmitted by DTC to and received by the Exchange Agent and forming a part of a book-entry transfer, which states that DTC has received an express acknowledgment from the tendering participant stating that such participant has received and agrees to be bound by the Letter of Transmittal.

The method of delivery of Restricted Notes, letters of transmittal and all other required documents is at your election and risk. If such delivery is by mail, it is recommended that you use registered mail, properly insured, with return receipt requested. In all cases, you should allow sufficient time to assure timely delivery. No letter of transmittal or Restricted Notes should be sent to us.

Signatures on a letter of transmittal or a notice of withdrawal, as the case may be, must be guaranteed unless the Restricted Notes surrendered for exchange are tendered:

- by a holder of the Restricted Notes who has not completed the box entitled "Special Issuance Instructions" or "Special Delivery Instructions" on the Letter of Transmittal; or

- for the account of an eligible institution (as defined below).

In the event that signatures on a letter of transmittal or a notice of withdrawal are required to be guaranteed, such guarantees must be by a firm which is a member of the Securities Transfer Agent Medallion Program, the Stock Exchanges Medallion Program or the New York Stock Exchange Medallion Program (each such entity being hereinafter referred to as an "eligible institution"). If Restricted Notes are registered in the name of a person other than the signer of the Letter of Transmittal, the Restricted Notes surrendered for exchange must be endorsed by, or be accompanied by a written instrument or instruments of transfer or exchange, in satisfactory form as we or the Exchange Agent determine in our discretion, duly executed by the registered holders with the signature thereon guaranteed by an eligible institution.

If the Letter of Transmittal is signed by a person or persons other than the registered holder or holders of Restricted Notes, such Restricted Notes must be endorsed or accompanied by powers of attorney signed exactly as the name(s) of the registered holder(s) that appear on the Restricted Notes.

If the Letter of Transmittal or any Restricted Notes or powers of attorney are signed by trustees, executors, administrators, guardians, attorneys-in-fact, officers of corporations or others acting in a fiduciary or representative capacity, such persons should so indicate when signing. Unless waived by us or the Exchange Agent, proper evidence satisfactory to us of their authority to so act must be submitted with the Letter of Transmittal.

If you are a beneficial owner whose Restricted Notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and wish to tender your Restricted Notes, you should promptly instruct the registered holder to tender such Restricted Notes on your behalf. Any registered holder that is a participant in DTC's book-entry transfer facility system may make book-entry delivery of the Restricted Notes by causing DTC to transfer the Restricted Notes into the Exchange Agent's account.

If you wish to tender your Restricted Notes in the Exchange Offer on your own behalf, prior to completing and executing the Letter of Transmittal and delivering your Restricted Notes, you must either make appropriate arrangements to register ownership of the Restricted Notes in your name with DTC or obtain a properly completed note power from the person in whose name the Restricted Notes are registered.

We or the Exchange Agent, in our discretion, will make a final and binding determination on all questions as to the validity, form, eligibility (including time of receipt) and acceptance of the Restricted Notes tendered for exchange. We reserve the right to reject any and all tenders not validly tendered or to not accept any tender which acceptance might, in our judgment or our counsel's, be unlawful. We also reserve the right to waive any defects or irregularities or conditions of the Exchange Offer as to any individual tender before the Expiration Date (including the right to waive the ineligibility of any holder who seeks to tender the Restricted Notes in the Exchange Offer). Our or the Exchange Agent's interpretation of the terms and conditions of the Exchange Offer (including the Letter of Transmittal and the instructions thereto) as to any particular tender either before or after the Expiration Date will be final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of the Restricted Notes for exchange must be cured within a reasonable period of time, as we determine. We are not nor is the Exchange Agent or any other person under any duty to notify you of any defect or irregularity with respect to your tender of the Restricted Notes for exchange, and no one will be liable for failing to provide such notification.

By tendering the Restricted Notes, you represent to us that: (1) any Exchange Notes to be received by you will be acquired in the ordinary course of your business, (2) you are not participating and have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes, (3) you are not an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours and (4) if you are a broker-dealer that will receive Exchange Notes for your own account in exchange for Restricted Notes that were acquired as a result of market-making or other trading activities, then you will deliver a prospectus (or, to the extent permitted by law, making available a prospectus to purchasers) in connection with any resale of such Exchange Notes. For further information regarding resales of the Exchange Notes by participating broker-dealers, see the discussion under the caption "Plan of Distribution".

If any holder or other person is an "affiliate" of ours (within the meaning of Rule 405 under the Securities Act), or is participating or has an arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes, that holder or other person cannot rely on the applicable interpretations of the staff of the SEC, may not tender its Restricted Notes in the Exchange Offer and must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

Each broker-dealer that receives the Exchange Notes for its own account in exchange for the Restricted Notes, where the Restricted Notes were acquired by it as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the Exchange Notes. By so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act (other than in connection with a resale of an unsold allotment from the original sale of the Restricted Notes).

Furthermore, any broker-dealer that acquired any of its Restricted Notes directly from us:

- may not rely on the applicable interpretation of the SEC staff's position contained in Exxon Capital Holdings Corp., SEC no-action letter (April 13, 1988), Morgan, Stanley & Co. Inc., SEC no-action letter (June 5, 1991) and Shearman & Sterling, SEC no-action letter (July 2, 1993); and

- must also be named as a selling noteholder in connection with the registration and prospectus delivery requirements of the Securities Act relating to any resale transaction.

By delivering a letter of transmittal or an agent's message, a holder or a beneficial owner (whose Restricted Notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee) will have or will be deemed to have irrevocably appointed the Exchange Agent as its agent and attorney-in-fact (with full knowledge that the Exchange Agent is also acting as an agent for us in connection with the Exchange Offer) with respect to the Restricted Notes, with full power of substitution (such power of attorney being deemed to be an irrevocable power coupled with an interest subject only to the right of withdrawal described in this prospectus), to receive for our account all benefits and otherwise exercise all rights of beneficial ownership of such Restricted Notes, in accordance with the terms and conditions of the Exchange Offer.

Each holder or beneficial owner will also have or be deemed to have represented and warranted to us that it has authority to tender, exchange, sell, assign and transfer the Restricted Notes it tenders and that, when the same are accepted for exchange, we will acquire good, marketable and unencumbered title to such Restricted Notes, free and clear of all liens, restrictions, charges and encumbrances, and that the Restricted Notes tendered are not subject to any proxies or adverse claims. Each holder and beneficial owner, by tendering its Restricted Notes, also agrees that it will comply with its obligations under the registration rights agreement.

**Acceptance of Restricted Notes for Exchange; Delivery of Exchange Notes**

Upon satisfaction or waiver of all of the conditions to the Exchange Offer, we will accept, promptly upon the Expiration Date, all the Restricted Notes validly tendered and not validly withdrawn and will issue the Exchange Notes promptly after acceptance of the Restricted Notes. See "The Exchange Offer-Conditions to the Exchange Offer".

For purposes of the Exchange Offer, we will be deemed to have accepted validly tendered Restricted Notes for exchange if and when we give written notice to the Exchange Agent.

The holder of each Restricted Note accepted for exchange will receive an Exchange Note of the corresponding series in an amount equal to the principal amount of the surrendered Restricted Note. Holders of the Exchange Notes on the relevant record date for the first interest payment date following the consummation of the Exchange Offer will receive interest accruing from the most recent date to which interest has been paid on the Restricted Notes or, if no interest has been paid, from the issue date of the Restricted Notes. Holders of the Exchange Notes will not receive any payment in respect of accrued interest on the corresponding series of Restricted Notes otherwise payable on any interest payment date, the record date for which occurs on or after the consummation of the Exchange Offer. Interest on the Restricted Notes accepted for exchange will cease to accrue upon the issuance of the Exchange Notes of the corresponding series.

In all cases, issuance of the Exchange Notes for the Restricted Notes of the corresponding series that are accepted for exchange will be made only after timely receipt by the Exchange Agent of an agent's message and a timely confirmation of book-entry transfer of the Restricted Notes into the Exchange Agent's account at DTC. If a tender is made pursuant to a letter of transmittal, a holder must complete, sign and date the letter of transmittal, or a fascimile thereof; have the signatures guaranteed if required by the letter of transmittal; and mail or otherwise deliver the signed letter of transmittal or the signed facsimile, the Restricted Notes and any other required documents to the Exchange Agent prior to 5:00 p.m., New York City time, on the Expiration Date.

If any tendered Restricted Notes are not accepted for any reason set forth in the terms and conditions of the Exchange Offer, such unaccepted Restricted Notes will be returned without expense to the holder or, in the case of Restricted Notes tendered by book-entry transfer into the Exchange Agent's account at DTC pursuant to the book-entry procedures described below, an account maintained by the holder or on the holder's behalf with DTC promptly upon the expiration or termination of the Exchange Offer.

**Book-Entry Transfers**

The Exchange Agent will make a request to establish an account for the Restricted Notes at DTC for purposes of the Exchange Offer within two business days after the date of this prospectus. Any financial institution that is a participant in DTC's systems may make book-entry delivery of the Restricted Notes by causing DTC to transfer those Restricted Notes into the Exchange Agent's account at DTC in accordance with DTC's procedure for transfer. This participant should transmit its acceptance to DTC on or prior to the Expiration Date. DTC will verify this acceptance, execute a book-entry transfer of the tendered Restricted Notes into the Exchange Agent's account at DTC and then send to the Exchange Agent confirmation of this book-entry transfer. A tender of Restricted Notes through a book-entry transfer into the Exchange Agent's account will only be effective if an agent's message or the Letter of Transmittal with any required signature guarantees and any other required documents are transmitted to and received or confirmed by the Exchange Agent at the address set forth below under the caption "-Exchange Agent", prior to 5:00 p.m., New York City time, on the Expiration Date. Delivery of documents to DTC in accordance with its procedures does not constitute delivery to the Exchange Agent.

**Withdrawal Rights**

For a withdrawal of a tender of any Restricted Notes to be effective, the Exchange Agent must either:

- receive a valid withdrawal request through the DTC's Automated Tender Offer Program system from the tendering DTC participant before the Expiration Date. Any such request for withdrawal must include the VOI number of the tender to be withdrawn and the name of the ultimate beneficial owner of the related Restricted Notes in order that such Restricted Notes may be withdrawn; or

- receive a written notice of withdrawal from a holder, delivered to one of the addresses set forth under "The Exchange Offer-Exchange Agent", which includes a statement that such holder is withdrawing its Restricted Notes and specifies (i) the name of the person having tendered the Restricted Notes to be withdrawn; (ii) the Restricted Notes to be withdrawn (including the aggregate principal amount of each series of such Restricted Notes); and (iii) where certificates for the Restricted Notes have been transmitted, the name in which such Restricted Notes are registered, if different from that of the withdrawing holder. If certificates for Restricted Notes have been delivered or otherwise identified to the Exchange Agent, then, prior to the release of such certificates, the withdrawing holder must also submit the serial numbers of the particular certificates to be withdrawn and a signed notice of withdrawal with signatures guaranteed by an eligible institution, unless such holder is an eligible institution.

Validly withdrawn Restricted Notes may be re-tendered by following the procedures described under "The Exchange Offer-Procedures for Tendering Restricted Notes" above at any time on or before 5:00 p.m., New York City time, on the Expiration Date.

We will determine all questions as to the validity, form and eligibility (including time of receipt) of notices of withdrawal. Any Restricted Notes so withdrawn will be deemed not to have been validly tendered for exchange. No Exchange Notes will be issued unless the Restricted Notes so withdrawn are validly re-tendered.

**Conditions to the Exchange Offer**

Notwithstanding any other provision of the Exchange Offer, we are not required to accept for exchange, or to issue the Exchange Notes in exchange for, any Restricted Notes and may terminate or amend the Exchange Offer, if any of the following events occur prior to the Expiration Date:

(a) the Exchange Offer violates any applicable law or applicable interpretation of the staff of the SEC; or

(b) there is threatened, instituted or pending any action or proceeding before, or any injunction, order or decree has been issued by, any court or governmental agency or other governmental regulatory or administrative agency or commission,

(1) seeking to restrain or prohibit the making or consummation of the Exchange Offer or any other transaction contemplated by the Exchange Offer, or assessing or seeking any damages as a result thereof, or

(2) resulting in a material delay in our ability to accept for exchange or exchange some or all of the Exchange Notes pursuant to the Exchange Offer;

or any statute, rule, regulation, order or injunction has been sought, proposed, introduced, enacted, promulgated or deemed applicable to the Exchange Offer or any of the transactions contemplated by the Exchange Offer by any government or governmental authority, domestic or foreign, or any action has been taken, proposed or threatened, by any government, governmental authority, agency or court, domestic or foreign, that in our reasonable judgment might, directly or indirectly, result in any of the consequences referred to in clauses (1) or (2) above or, in our reasonable judgment, might result in the holders of the Exchange Notes having obligations with respect to resales and transfers of the Exchange Notes which are greater than those described in the interpretation of the SEC referred to in "-Procedures for Tendering Restricted Notes", or would otherwise make it inadvisable to proceed with the Exchange Offer; or

(c) we have not obtained any governmental approval which we deem necessary for the consummation of the Exchange Offer; or

(d) there has occurred:

(1) any general suspension of, or general limitation on, prices for, or trading in, securities on any national securities exchange or in the over-the-counter market,

(2) any limitation by a governmental agency or authority which may adversely affect our ability to complete the transactions contemplated by the Exchange Offer,

(3) a declaration of a banking moratorium or any suspension of payments in respect of banks in the United States or any limitation by any governmental agency or authority which adversely affects the extension of credit, or

(4) a commencement of a war, armed hostilities or other similar international calamity directly or indirectly involving the United States or, in the case of any of the foregoing existing at the time of the commencement of the Exchange Offer, a material acceleration or worsening thereof; or

(e) any change (or any development involving a prospective change) has occurred or is threatened in our business, properties, assets, liabilities, financial condition, operations, results of operations or prospects and our subsidiaries taken as a whole that, in our reasonable judgment, is or may be adverse to us, or we have become aware of facts that, in our reasonable judgment, have or may have adverse significance with respect to the value of the Restricted Notes or the Exchange Notes;

which, in each case, and regardless of the circumstances (including any action by us) giving rise to any such condition, makes it inadvisable, in our reasonable judgment, to proceed with the Exchange Offer, such acceptance for exchange or such exchange.

The foregoing conditions are for our benefit and may be asserted by us regardless of the circumstances giving rise to any condition or may be waived by us in whole or in part at any time in our reasonable discretion. Our failure at any time to exercise any of the foregoing rights will not be deemed a waiver of any such right and each such right will be deemed an ongoing right which may be asserted at any time.

In addition, we will not accept for exchange any Restricted Notes tendered, and no Exchange Notes will be issued in exchange for any such Restricted Notes, if at such time any stop order is threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the Indenture under the Trust Indenture Act of 1939, as amended.

**Exchange Agent**

We have appointed The Bank of New York Mellon Trust Company, N.A. as the Exchange Agent for the Exchange Offer. Questions and requests for assistance, requests for additional copies of this prospectus, the letter of transmittal or other documents should be directed to the Exchange Agent addressed as follows:

The Bank of New York Mellon Trust Company, N.A., Exchange Agent

*By Registered or Certified Mail, Overnight Delivery:*
The Bank of New York Mellon Trust Company, N.A.
c/o The Bank of New York Mellon Corporation
Corporate Trust Operations
111 Sanders Creek Parkway
East Syracuse, NY 13057
Attn: Eric Herr
Tel. No.: 315-414-3362

*For Facsimile Transmission (for Eligible Institutions only):*

732-667-9408

*E-mail Inquiries:*

CT_REORG_UNIT_INQUIRIES@BNYMELLON.COM

**DELIVERY OF THE LETTER OF TRANSMITTAL TO AN ADDRESS OTHER THAN AS SET FORTH ABOVE OR TRANSMISSION OF SUCH LETTER OF TRANSMITTAL VIA FACSIMILE OTHER THAN AS SET FORTH ABOVE DOES NOT CONSTITUTE A VALID DELIVERY OF THE LETTER OF TRANSMITTAL.**

**Fees and Expenses**

We will pay the Exchange Agent customary fees for its services, reimburse the Exchange Agent for its reasonable out-of-pocket expenses incurred in connection with the provision of these services and pay other registration expenses, including registration and filing fees, fees and expenses of compliance with federal securities and state blue sky securities laws, printing expenses, messenger and delivery services and telephone fees and disbursements to our counsel, application and filing fees and any fees and disbursements to our independent certified public accountants. We will not make any payment to brokers, dealers or others soliciting acceptances of the Exchange Offer.

This solicitation is being made primarily by electronic means. Additional solicitation may be made by telephone, facsimile or in person by our and our affiliates' officers and regular employees and by persons so engaged by the Exchange Agent.

**Accounting Treatment**

We will record the Exchange Notes at the same carrying value as the Restricted Notes, as reflected in our accounting records on the date of the exchange. Accordingly, we will not recognize any gain or loss for accounting purposes. The expenses of the Exchange Offer will be amortized over the terms of the Exchange Notes.

**Transfer Taxes**

You will not be obligated to pay any transfer taxes in connection with the tender of the Restricted Notes in the Exchange Offer unless you instruct us to register the Exchange Notes in the name of, or request that the Restricted Notes not tendered or not accepted in the Exchange Offer be returned to, a person other than the registered tendering holder or unless a transfer tax is imposed for any reason other than the exchange of Restricted Notes in connection with the Exchange Offer. In those cases, the tendering holder will be responsible for the payment of any applicable transfer tax. If the tendering holder does not submit satisfactory evidence of payment of these taxes or exemption therefrom with the Letter of Transmittal, the amount of these transfer taxes will be billed directly to the tendering holder.

**Consequences of Exchanging or Failing to Exchange Restricted Notes**

The information below concerning specific interpretations of, and positions taken by, the staff of the SEC is not intended to constitute legal advice, and holders who wish to participate in the Exchange Offer should consult their own legal advisors with respect to those matters.

If you do not exchange your Restricted Notes for the Exchange Notes in the Exchange Offer, your Restricted Notes will continue to be subject to the provisions of the indenture regarding transfer and exchange of the Restricted Notes and the restrictions on transfer of the Restricted Notes imposed by the Securities Act and state securities law. These transfer restrictions are required because the Restricted Notes were issued under an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. In general, the Restricted Notes may not be offered or sold unless registered under the Securities Act, except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not plan to register the Restricted Notes under the Securities Act.

Based on interpretations by the staff of the SEC, as detailed in a series of no-action letters issued to third parties, we believe that the Exchange Notes issued in the Exchange Offer may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery requirements of the Securities Act as long as:

- any Exchange Notes to be received by you will be acquired in the ordinary course of your business;
- you are not participating and have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes; and
- you are not an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours.

If you are an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours, or are participating or have an arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes:

- you cannot rely on the applicable interpretations of the staff of the SEC;
- you will not be entitled to participate in the Exchange Offer; and
- you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

We do not intend to seek our own interpretation regarding the Exchange Offer, and we cannot assure you that the staff of the SEC would make a similar determination with respect to the Exchange Notes as it has in other interpretations to third parties.

Each holder of the Restricted Notes who wishes to exchange such Restricted Notes for the related Exchange Notes in the Exchange Offer represents that:

- any Exchange Notes to be received by it will be acquired in the ordinary course of its business;
- it is not participating and has no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Notes;
- it is not an "affiliate" (within the meaning of Rule 405 under the Securities Act) of ours; and
- if such holder is a broker-dealer that will receive Exchange Notes for its own account in exchange for Restricted Notes that were acquired as a result of market-making or other trading activities, then such holder will deliver a prospectus (or, to the extent permitted by law, make available a prospectus to purchaser) in connection with any resale of such Exchange Notes. For further information regarding resales of the Exchange Notes by participating broker-dealers, see the discussion under the caption "Plan of Distribution".

As discussed above, in connection with resales of the Exchange Notes, any participating broker-dealer must deliver a prospectus meeting the requirements of the Securities Act. The staff of the SEC has taken the position that participating broker-dealers may fulfill their prospectus delivery requirements with respect to the Exchange Notes, other than a resale of an unsold allotment from the original sale of the Restricted Notes, with the prospectus contained in the Exchange Offer Registration Statement. Under the registration rights agreement, we have agreed, for a period of 30 days following the expiration of the Exchange Offer, to make available a prospectus meeting the requirements of the Securities Act to any participating broker-dealer for use in connection with any resale of any Exchange Notes acquired in the Exchange Offer.

**Neither we nor our board of directors make any recommendation to holders of the Restricted Notes as to whether to tender or refrain from tendering all or any portion of any series of their Restricted Notes pursuant to the Exchange Offer. Moreover, no one has been authorized to make any such recommendation. Holders of the Restricted Notes must make their own decision whether to tender pursuant to the Exchange Offer and, if so, the aggregate amount of the Restricted Notes to tender, after reading this prospectus and the Letter of Transmittal and consulting with their advisors, if any, based on their own financial position and requirements.**

## DESCRIPTION OF THE EXCHANGE NOTES

### General

As used in this section, the terms "we," "us" and "our" refer to Pacific Gas and Electric Company, and not to any of its subsidiaries.

The 2018 Exchange Notes, 2027 Exchange Notes and 2047 Exchange Notes each constitute a separate series of debt securities under the Indenture (as defined below). Any Restricted Notes of a series that remain outstanding after completion of the Exchange Offer, together with the Exchange Notes of such series issued in the Exchange Offer, will be treated as a single class of securities under the Indenture.

The terms of the Exchange Notes will be substantially identical to the terms of the corresponding series of the Restricted Notes, except that the Exchange Notes will not contain terms with respect to additional interest for failure to fulfill certain of our obligations under the registration rights agreement and transfer restrictions. Unless the context otherwise requires, under this section "Description of the Exchange Notes": (1) references to the "senior notes" include the Restricted Notes and the Exchange Notes; (2) references to the "2018 notes" include the 2018 Restricted Notes and the 2018 Exchange Notes; (3) references to the "2027 notes" include the 2027 Restricted Notes and the 2027 Exchange Notes; (4) references to the "2047 notes" include the 2047 Restricted Notes and the 2047 Exchange Notes; and (5) references to the "fixed rate notes" include the 2027 Restricted Notes, 2047 Restricted Notes, 2027 Exchange Notes and 2047 Exchange Notes.

The 2018 Exchange Notes are being offered in the aggregate principal amount of $500,000,000 and will mature on November 28, 2018.

The 2027 Exchange Notes are being offered in the aggregate principal amount of $1,150,000,000 and will mature on December 1, 2027.

The 2047 Exchange Notes are being offered in the aggregate principal amount of $850,000,000 and will mature on December 1, 2047.

We will issue the Exchange Notes under the indenture (the "Indenture"), dated November 29, 2017 (the "Restricted Notes Issue Date"), between us and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee"). We will issue the Exchange Notes in minimum denominations of $100,000 and integral multiples of $1,000 in excess thereof.

We will issue the Exchange Notes in the form of one or more global securities, which will be deposited with, or on behalf of, The Depository Trust Company, or DTC, and registered in the name of DTC's nominee. Information regarding DTC's book-entry system is set forth under "Book-Entry Settlement and Clearance." The Indenture includes the terms made part thereof by reference to the Trust Indenture Act of 1939, as amended (the "1939 Act"), as a result of the Indenture being qualified under the 1939 Act. Pursuant to the 1939 Act, if a default occurs on the senior notes, The Bank of New York Mellon Trust Company, N.A. may be required to resign as Trustee under the Indenture if it has a conflicting interest (as defined in the 1939 Act), unless the default is cured, duly waived or otherwise eliminated within 90 days.

The following description is only a summary of the material provisions of the Indenture and does not purport to be complete and is qualified in its entirety by reference to the provisions of the Indenture, including the definitions therein of certain terms used below. We urge you to read the Indenture because the Indenture, not this description, defines your rights as holders of the applicable senior notes. You may request copies of the Indenture at our address set forth under the heading "Where You Can Find More Information".

We may, without consent of the holders of senior notes, issue additional indebtedness. Such additional indebtedness could be issued in the form of additional notes under the Indenture, having the same terms in all respects to the applicable series of senior notes (except for the offering price and the issue date and, in some cases, the first interest payment date) so that those additional notes will be consolidated and form a single series with the other outstanding senior notes of such series; provided that if the applicable series of senior notes and the same series of additional notes are not fungible for U.S. federal income tax purposes, a separate CUSIP number will be issued for any such additional notes.

**Interest**

***Interest on the 2018 Notes***

The 2018 notes bear interest from the Restricted Notes Issue Date or from the most recent date to which interest has been paid or provided for. We will pay interest on the 2018 notes quarterly on May 28, 2018, August 28, 2018 and November 28, 2018 (each, an "interest payment date"), to the persons in whose names the 2018 notes are registered at the close of business on the 15th calendar day (whether or not a Business Day) immediately preceding the related interest payment date; provided, however, that interest payable on the maturity date shall be payable to the person to whom the principal of such 2018 notes shall be payable. Interest on the 2018 notes will be computed on the basis of the actual number of days elapsed over a 360-day year.

As used in this section "Interest on the 2018 Notes," "Business Day" means any day (1) that is not a Saturday or Sunday and that is not a day on which banking institutions are authorized or obligated by law or executive order to close in the City of New York and, for any place of payment outside of the City of New York, in such place of payment, and (2) that is also a "London business day", which is a day on which dealings in deposits in U.S. dollars are transacted in the London interbank market.

***Rate of Interest on the 2018 Notes***

The interest rate on the 2018 notes was initially reset on February 28, 2018 and will be reset quarterly on May 28, 2018 and August 28, 2018 (each, an "interest reset date"). The 2018 notes will bear interest at a per annum rate equal to three-month LIBOR (as defined below) for the applicable interest reset period (as defined below) plus 0.23% (23 basis points). The interest rate on the 2018 notes will in no event be higher than the maximum rate permitted by New York law as the same may be modified by United States law of general application. Additionally, the interest rate on the 2018 notes will in no event be lower than zero.

Each "interest reset period" will be the period from and including an interest reset date to but excluding the immediately succeeding interest reset date; provided that the final interest reset period for the 2018 notes will be the period from and including the interest reset date immediately preceding the maturity date of such 2018 notes to but excluding the maturity date.

If any interest reset date would otherwise be a day that is not a Business Day, the interest reset date will be postponed to the immediately succeeding day that is a Business Day, except that if that Business Day is in the immediately succeeding calendar month, the interest reset date shall be the immediately preceding Business Day.

The interest rate in effect on each day will be (i) if that day is an interest reset date, the interest rate determined as of the interest determination date (as defined below) immediately preceding such interest reset date or (ii) if that day is not an interest reset date, the interest rate determined as of the interest determination date immediately preceding the most recent interest reset date.

***Interest Rate Determination on the 2018 Notes***

The interest rate applicable to each interest reset period commencing on the related interest reset date will be the rate determined as of the applicable interest determination date. The "interest determination date" will be the second London business day immediately preceding the applicable interest reset date.

The Bank of New York Mellon Trust Company, N.A., or its successor appointed by us, will act as calculation agent. Three-month LIBOR will be determined by the calculation agent as of the applicable interest determination date in accordance with the following provisions:

(i) LIBOR is the rate for deposits in U.S. dollars for the three-month period which appears on Reuters Screen LIBOR01 Page (as defined below) at approximately 11:00 a.m., London time, on the applicable interest determination date. "Reuters Screen LIBOR01 Page" means the display designated on page "LIBOR01" on Reuters Screen (or such other page as may replace the LIBOR01 page on that service, any successor service or such other service or services as may be nominated by the British Bankers' Association for the purpose of displaying London interbank offered rates for U.S. dollar deposits). If no rate appears on Reuters Screen LIBOR01 Page, LIBOR for such interest determination date will be determined in accordance with the provisions of paragraph (ii) below.

(ii) With respect to an interest determination date on which no rate appears on Reuters Screen LIBOR01 Page as of approximately 11:00 a.m., London time, on such interest determination date, the calculation agent shall request the principal London offices of each of four major reference banks in the London interbank market selected by us to provide the calculation agent with a quotation of the rate at which deposits of U.S. dollars having a three-month maturity, commencing on the second London business day immediately following such interest determination date, are offered by it to prime banks in the London interbank market as of approximately 11:00 a.m., London time, on such interest determination date in a principal amount equal to an amount of not less than U.S. $1,000,000 that is representative for a single transaction in such market at such time. If at least two such quotations are provided, LIBOR for such interest determination date will be the arithmetic mean of such quotations as calculated by the calculation agent. If fewer than two quotations are provided, LIBOR for such interest determination date will be the arithmetic mean of the rates quoted as of approximately 11:00 a.m., New York City time, on such interest determination date by three major banks selected by us for loans in U.S. dollars to leading European banks having a three-month maturity commencing on the second London business day immediately following such interest determination date and in a principal amount equal to an amount of not less than U.S. $1,000,000 that is representative for a single transaction in such market at such time; provided, however, that if the banks selected as aforesaid by us are not quoting such rates as mentioned in this sentence, LIBOR for such interest determination date will be LIBOR determined with respect to the immediately preceding interest determination date.

All percentages resulting from any calculation of any interest rate for the 2018 notes will be rounded, if necessary, to the nearest one hundred thousandth of a percentage point, with five one-millionths of a percentage point rounded upward (e.g., 9.876545% (or .09876545) would be rounded to 9.87655% (or .0987655)), and all dollar amounts will be rounded to the nearest cent, with one-half cent being rounded upward.

Promptly upon such determination, the calculation agent will notify us and the Trustee (if the calculation agent is not the Trustee) of the interest rate for the new interest reset period. Upon request of a holder of the 2018 notes, the calculation agent will provide to such holder the interest rate in effect on the date of such request and, if determined, the interest rate for the next interest reset period.

All calculations made by the calculation agent for the purposes of calculating interest on the 2018 notes shall be conclusive and binding on the holders and us, absent manifest errors.

***Interest on the Fixed Rate Notes***

The 2027 notes will bear interest from the Restricted Notes Issue Date or from the most recent date to which interest has been paid or provided for at 3.30% per annum, payable semiannually on each June 1 and December 1, commencing on June 1, 2018 to holders of record at the close of business on May 15 and November 15 immediately preceding the interest payment date.

The 2047 notes will bear interest from the Restricted Notes Issue Date or from the most recent date to which interest has been paid or provided for at 3.95% per annum, payable semiannually on each June 1 and December 1, commencing on June 1, 2018, to holders of record at the close of business on May 15 and November 15 immediately preceding the interest payment date.

Interest on the fixed rate senior notes will be computed on the basis of a 360-day year consisting of twelve 30-day months.

***Interest Provisions for all Senior Notes***

Interest payable on each interest payment date will be paid to the person in whose name that senior note is registered as of the close of business on the regular record date for the interest payment date. However, interest payable at maturity will be paid to the person to whom the principal is paid. If there has been a default in the payment of interest on a series of senior notes, the defaulted interest may be paid to the holders of the senior notes of such series as of a date between 10 and 30 days before the date we propose for payment of defaulted interest or in any other manner not inconsistent with the requirements of any securities exchange on which those senior notes may be listed.

Interest payable on any interest payment date or the maturity date shall be the amount of interest accrued from, and including, the immediately preceding interest payment date in respect of which interest has been paid or duly provided for (or from and including the Restricted Notes Issue Date, if no interest has been paid or duly provided for with respect to the senior notes) to, but excluding, such interest payment date or maturity date, as the case may be. If any interest payment date (other than the maturity date) is not a business day at the relevant place of payment, we will pay interest on the next day that is a business day at such place of payment as if payment were made on the date such payment was due, and no interest will accrue on the amounts so payable for the period from and after such date to the immediately succeeding business day, except that, in the case of the 2018 notes, if such business day is in the immediately succeeding calendar month, such interest payment date (other than the maturity date) shall be the immediately preceding business day. If the maturity date is not a business day at the relevant place of payment, we will pay interest, if any, and principal and premium, if any, on the next day that is a business day at such place of payment as if payment were made on the date such payment was due, and no interest will accrue for the intervening period.

**Ranking**

The senior notes will be our direct, unsecured and unsubordinated obligations and will rank equally with all our other existing and future unsecured and unsubordinated obligations. The senior notes will be effectively subordinated to all our secured debt. As of December 31, 2017, we had approximately $17.4 billion of long-term debt outstanding (net of current portion), none of which was secured. The Indenture contains no restrictions on the amount of additional indebtedness that may be incurred by us.

**No Redemption for 2018 Notes**

The 2018 notes will not be redeemable prior to maturity. Subject to the foregoing and to applicable law (including, without limitation, United States federal securities laws), we or our affiliates may, at any time and from time to time, purchase outstanding 2018 notes by tender, in the open market or by private agreement.

**Optional Redemption for Fixed Rate Notes**

***Optional Redemption for 2027 Notes***

At any time prior to September 1, 2027 (the date that is three months prior to the maturity date), we may, at our option, redeem the 2027 notes in whole or in part at a redemption price equal to the greater of:

- 100% of the principal amount of the 2027 notes to be redeemed; or
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2027 notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) calculated as if the maturity date of the 2027 notes was September 1, 2027 (the date that is three months prior to the maturity date), discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate plus 15 basis points,

plus, in either case, accrued and unpaid interest to, but not including, the redemption date.

At any time on or after September 1, 2027 (the date that is three months prior to the maturity date), we may redeem the 2027 notes, in whole or in part, at 100% of the principal amount of the 2027 notes being redeemed, plus accrued and unpaid interest to, but not including, the redemption date.

As used in this section "Optional Redemption for 2027 Notes," the following terms shall have the following meanings:

"Comparable Treasury Issue" means the United States Treasury security selected by the applicable Quotation Agent as having a maturity comparable to the remaining term of the 2027 notes to be redeemed, assuming, for such purpose, that the 2027 notes matured on September 1, 2027 (the date that is three months prior to the maturity date (the "remaining term")), that would be used, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the 2027 notes to be redeemed.

"Quotation Agent" means the Reference Treasury Dealer appointed by us for the 2027 notes.

***Optional Redemption for 2047 Notes***

At any time prior to June 1, 2047 (the date that is six months prior to the maturity date), we may, at our option, redeem the 2047 notes in whole or in part at a redemption price equal to the greater of:

- 100% of the principal amount of the 2047 notes to be redeemed; or
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the 2047 notes to be redeemed (not including any portion of payments of interest accrued as of the redemption date) calculated as if the maturity date of the 2047 notes was June 1, 2047 (the date that is six months prior to the maturity date), discounted to the redemption date on a semiannual basis at the Adjusted Treasury Rate plus 20 basis points,

plus, in either case, accrued and unpaid interest to, but not including, the redemption date.

At any time on or after June 1, 2047 (the date that is six months prior to the maturity date), we may redeem the 2047 notes, in whole or in part, at 100% of the principal amount of the 2047 notes being redeemed plus accrued and unpaid interest to, but not including, the redemption date.

As used in this section "Optional Redemption for 2047 Notes," the following terms shall have the following meanings:

"Comparable Treasury Issue" means the United States Treasury security selected by the applicable Quotation Agent as having a maturity comparable to the remaining term of the 2047 notes to be redeemed, assuming, for such purpose, that the 2047 notes matured on June 1, 2047 (the date that is six months prior to the maturity date (the "remaining term")), that would be used, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the 2047 notes to be redeemed.

"Quotation Agent" means the Reference Treasury Dealer appointed by us for the 2047 notes.

***General Optional Redemption Terms Applicable to the Fixed Rate Notes***

The redemption price of the fixed rate notes will be calculated assuming a 360-day year consisting of twelve 30-day months.

We will send notice of any redemption of the fixed rate notes at least 10 days but not more than 60 days before the redemption date to each registered holder of the fixed rate notes to be redeemed.

Unless we default in payment of the redemption price of the fixed rate notes, on and after the redemption date, interest will cease to accrue on the fixed rate notes or portions of the fixed rate notes called for redemption.

We will have the right to provide conditional redemption notices for redemptions that are contingent upon the occurrence or nonoccurrence of an event or condition that cannot be ascertained prior to the time we are required to notify holders of the redemption. A conditional notice may state that if we have not deposited redemption funds with the Trustee or a paying agent on or before the redemption date or we have directed the Trustee or paying agent not to apply money deposited with it for redemption of fixed rate notes, we will not be required to redeem the fixed rate notes on the redemption date.

If we redeem only some of the fixed rate notes, DTC's practice is to choose by lot the amount to be redeemed from the fixed rate notes held by each of its participating institutions. DTC will give notice to these participants, and these participants will give notice to any "street name" holders of any indirect interests in the fixed rate notes to be redeemed according to arrangements among them. These notices may be subject to statutory or regulatory requirements. We will not be responsible for giving notice of a redemption of the fixed rate notes to be redeemed to anyone other than the registered holders of the fixed rate notes to be redeemed, which is currently DTC. If fixed rate notes to be redeemed are no longer held through DTC and fewer than all the fixed rate notes are to be redeemed, selection of fixed rate notes for redemption will be made by the Trustee in accordance with the procedures of the applicable Depositary.

Subject to the foregoing and to applicable law (including, without limitation, United States federal securities laws), we or our affiliates may, at any time and from time to time, purchase outstanding fixed rate notes by tender, in the open market or by private agreement.

As used in this section "General Optional Redemption Terms Applicable to the Fixed Rate Notes," the following terms shall have the following meanings:

"Adjusted Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for the redemption date.

"Business Day" means any day that is not a day on which banking institutions in New York City are authorized or required by law or regulation to close.

"Comparable Treasury Price" means, with respect to any redemption date:

- the average of the Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest of the Reference Treasury Dealer Quotations; or

- if we obtain fewer than four Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations so received.

"Reference Treasury Dealer" means (1) each of Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC and their respective successors, unless any of them ceases to be a primary dealer in certain U.S. government securities ("Primary Treasury Dealer"), in which case we shall substitute another Primary Treasury Dealer; and (2) any other Primary Treasury Dealer selected by us.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that redemption date.

**No Sinking Fund for Senior Notes**

There is no provision for a sinking fund for the senior notes.

**Covenants**

***Restrictions on Liens and Sale and Leaseback Transactions***

The Indenture does not permit us or any of our significant subsidiaries (as defined below) to, (i) issue, incur, assume or permit to exist any debt (as defined below) secured by a lien (as defined below) on any of our principal property (as defined below) or any of our significant subsidiaries' principal property, whether that principal property was owned on the Restricted Notes Issue Date or thereafter acquired, unless we provide that the senior notes will be equally and ratably secured by such liens for as long as any such debt shall be so secured or (ii) incur or permit to exist any attributable debt (as defined below) in respect of principal property; provided, however, that the foregoing restriction will not apply to the following:

- any lien existing on the Restricted Notes Issue Date;
- to the extent we or a significant subsidiary consolidates with, or merges with or into, another entity, liens on the property of the entity securing debt in existence on the date of the consolidation or merger, provided that the debt and liens were not created or incurred in anticipation of the consolidation or merger and that the liens do not extend to or cover any of our or a significant subsidiary's principal property;
- liens on property acquired after the Restricted Notes Issue Date and existing at the time of acquisition, as long as the lien was not created or incurred in anticipation thereof and does not extend to or cover any other principal property;
- liens of any kind, including purchase money liens, conditional sales agreements or title retention agreements and similar agreements, upon any property acquired, constructed, developed or improved by us or a significant subsidiary (whether alone or in association with others) which do not exceed the cost or value of the property acquired, constructed, developed or improved and which are created prior to, at the time of, or within 12 months after the acquisition (or in the case of property constructed, developed or improved, within 12 months after the completion of the construction, development or improvement and commencement of full commercial operation of the property, whichever is later) to secure or provide for the payment of any part of the purchase price or cost thereof; provided that the liens do not extend to any principal property other than the property so acquired, constructed, developed or improved;
- liens in favor of the United States, any state or any foreign country or any department, agency or instrumentality or any political subdivision of the foregoing to secure payments pursuant to any contract or statute or to secure any indebtedness incurred for the purpose of financing all or any part of the purchase price or cost of constructing or improving the property subject to the lien, including liens related to governmental obligations the interest on which is tax-exempt under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"), or any successor section of the Code;
- liens in favor of us, one or more of our significant subsidiaries, one or more of our wholly owned subsidiaries or any of the foregoing combination; and
- replacements, extensions or renewals (or successive replacements, extensions or renewals), in whole or in part, of any lien or of any agreement referred to in the bullet points above or replacements, extensions or renewals of the debt secured thereby (to the extent that the amount of the debt secured by the lien is not increased from the amount originally so secured, plus any premium, interest, fee or expenses payable in connection with any replacements, refundings, refinancings, remarketings, extensions or renewals); provided that replacement, extension or renewal is limited to all or a part of the same property (plus improvements thereon or additions or accessions thereto) that secured the lien replaced, extended or renewed.

Notwithstanding the restriction described above, we or any significant subsidiary may (i) issue, incur or assume debt secured by a lien not described in the immediately preceding seven bullet points on any principal property owned on the Restricted Notes Issue Date or thereafter acquired without providing that the outstanding senior notes be equally and ratably secured by such liens and (ii) issue or permit to exist attributable debt in respect of principal property, in either case, so long as the aggregate amount of that secured debt and attributable debt, together with the aggregate amount of all other debt secured by liens on principal property not described in the immediately preceding seven bullet points then outstanding and all other attributable debt in respect of principal property, does not exceed 10% of our net tangible assets, as determined by us as of a month end not more than 90 days prior to the closing or consummation of the proposed transaction.

For these purposes:

- “attributable debt” in respect of a sale and leaseback transaction means, at the time of determination, the present value of the obligation of the lessee for net rental payments during the remaining term of the lease included in the sale and leaseback transaction, including any period for which the lease has been extended or may, at the option of the lessor, be extended. The present value shall be calculated using a discount rate equal to the rate of interest implicit in the transaction, determined in accordance with generally accepted accounting principles, or GAAP.

- “capital lease obligation” means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet in accordance with GAAP.

- “debt” means any debt of ours for money borrowed and guarantees by us of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- “debt” of a significant subsidiary means any debt of such significant subsidiary for money borrowed and guarantees by the significant subsidiary of debt for money borrowed but in each case excluding liabilities in respect of capital lease obligations or swap agreements.

- “excepted property” means any right, title or interest of us or any of our significant subsidiaries in, to or under any of the following property, whether owned on the Restricted Notes Issue Date or thereafter acquired:

  - all money, investment property and deposit accounts (as those terms are defined in the California Commercial Code as in effect on March 11, 2004 (which is the date of the indenture governing certain of the Company’s outstanding senior notes)), and all cash on hand or on deposit in banks or other financial institutions, shares of stock, interests in general or limited partnerships or limited liability companies, bonds, notes, other evidences of indebtedness and other securities, of whatever kind and nature;

  - all accounts, chattel paper, commercial tort claims, documents, general intangibles, instruments, letter-of-credit rights and letters of credit (as those terms are defined in the California Commercial Code as in effect on March 11, 2004), with certain exclusions such as licenses and permits to use the real property of others, and all contracts, leases (other than the lease of certain real property at our Diablo Canyon power plant), operating agreements and other agreements of whatever kind and nature; and all contract rights, bills and notes;

  - all revenues, income and earnings, all accounts receivable, rights to payment and unbilled revenues, and all rents, tolls, issues, product and profits, claims, credits, demands and judgments, including any rights in or to rates, revenue components, charges, tariffs, or amounts arising therefrom, or in any amounts that are accrued and recorded in a regulatory account for collection by us or any significant subsidiary;

  - all governmental and other licenses, permits, franchises, consents and allowances including all emission allowances (or similar rights) created under any similar existing or future law relating to abatement or control of pollution of the atmosphere, water or soil, other than all licenses and permits to use the real property of others, franchises to use public roads, streets and other public properties, rights of way and other rights, or interests relating to the occupancy or use of real property;

  - all patents, patent licenses and other patent rights, patent applications, trade names, trademarks, copyrights and other intellectual property, including computer software and software licenses;

  - all claims, credits, choses in action, and other intangible property;

  - all automobiles, buses, trucks, truck cranes, tractors, trailers, motor vehicles and similar vehicles and movable equipment; all rolling stock, rail cars and other railroad equipment; all vessels, boats, barges and other marine equipment; all airplanes, helicopters, aircraft engines and other flight equipment; and all parts, accessories and supplies used in connection with any of the foregoing;

- all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; all materials, supplies, inventory and other items of personal property that are consumable (otherwise than by ordinary wear and tear) in their use in the operation of the principal property; all fuel, whether or not that fuel is in a form consumable in the operation of the principal property, including separate components of any fuel in the forms in which those components exist at any time before, during or after the period of the use thereof as fuel; all hand and other portable tools and equipment; and all furniture and furnishings;

- all personal property the perfection of a security interest in which is not governed by the California Commercial Code;

- all oil, gas and other minerals (as those terms are defined in the California Commercial Code as in effect on March 11, 2004) and all coal, ore, gas, oil and other minerals and all timber, and all rights and interests in any of the foregoing, whether or not the minerals or timber have been mined or extracted or otherwise separated from the land; and all electric energy and capacity, gas (natural or artificial), steam, water and other products generated, produced, manufactured, purchased or otherwise acquired by us or any significant subsidiary;

- all property which is the subject of a lease agreement other than a lease agreement that results from a sale and leaseback transaction designating us or any significant subsidiary as lessee and all our, or a significant subsidiary's right, title and interest in and to that property and in, to and under that lease agreement, whether or not that lease agreement is intended as security (other than certain real property leased at our Diablo Canyon power plant and the related lease agreement);

- real, personal and mixed properties of an acquiring or acquired entity unless otherwise made a part of principal property; and

- all proceeds (as that term is defined in the California Commercial Code as in effect on March 11, 2004) of the property listed in the preceding bullet points.

- "lien" means any mortgage, deed of trust, pledge, security interest, encumbrance, easement, lease, reservation, restriction, servitude, charge or similar right and any other lien of any kind, including, without limitation, any conditional sale or other title retention agreement, any lease of a similar nature, and any defect, irregularity, exception or limitation in record title or, when the context so requires, any lien, claim or interest arising from anything described in this bullet point.

- "net tangible assets" means the total amount of our assets determined on a consolidated basis in accordance with GAAP, less (i) the sum of our consolidated current liabilities determined in accordance with GAAP and (ii) the amount of our consolidated assets classified as intangible assets determined in accordance with GAAP, including, but not limited to, such items as goodwill, trademarks, trade names, patents, and unamortized debt discount and expense and regulatory assets carried as an asset on our consolidated balance sheet.

- "principal property" means any property of ours or any of our significant subsidiaries, as applicable, other than excepted property.

- "significant subsidiary" has the meaning specified in Rule l-02(w) of Regulation S-X under the Securities Act of 1933, as amended (the "Securities Act"); provided that, significant subsidiary shall not include any corporation or other entity substantially all the assets of which are excepted property.

- "swap agreement" means any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions.

***Consolidation, Merger, Conveyance or Other Transfer***

We may not consolidate with or merge with or into any other person (as defined below) or convey, otherwise transfer or lease all or substantially all of our principal property to any person unless:

- the person formed by that consolidation or into which we are merged or the person which acquires by conveyance or other transfer, or which leases, all or substantially all of the principal property is a corporation, partnership, limited liability company, association, company, joint stock company or business trust, organized and existing under the laws of the United States, or any state thereof or the District of Columbia;

- the person executes and delivers to the Trustee a supplemental indenture that in the case of a consolidation, merger, conveyance or other transfer, or in the case of a lease if the term thereof extends beyond the last stated maturity of the senior notes then outstanding, contains an assumption by the successor person of the due and punctual payment of the principal of and premium, if any, and interest, if any, on all senior notes then outstanding and the performance and observance of every covenant and condition under the Indenture to be performed or observed by us;

- in the case of a lease, the lease is made expressly subject to termination by us or by the Trustee at any time during the continuance of an event of default under the Indenture;

- immediately after giving effect to the transaction and treating any indebtedness that becomes our obligation as a result of the transaction as having been incurred by us at the time of the transaction, no default or event of default under the Indenture shall have occurred and be continuing; and

- we have delivered to the Trustee an officer's certificate and an opinion of counsel, each stating that the merger, consolidation, conveyance, lease or transfer, as the case may be, fully complies with all provisions of the Indenture; provided, however, that the delivery of the officer's certificate and opinion of counsel shall not be required with respect to any merger, consolidation, conveyance, lease or transfer between us and any of our wholly owned subsidiaries.

Notwithstanding the foregoing, we may merge or consolidate with or transfer all or substantially all of our assets to an affiliate that has no significant assets or liabilities and was formed solely for the purpose of changing our jurisdiction of organization or our form of organization or for the purpose of forming a holding company; provided that the amount of our indebtedness is not increased; and provided, further that the successor assumes all of our obligations under the Indenture.

In the case of the conveyance or other transfer of all or substantially all of our principal property to any person as contemplated under the Indenture, upon the satisfaction of all the conditions described above, we (as we would exist without giving effect to the transaction) would be released and discharged from all obligations and covenants under the Indenture and under the senior notes then outstanding unless we elect to waive the release and discharge.

The meaning of the term "substantially all" has not been definitely established and is likely to be interpreted by reference to applicable state law if and at the time the issue arises and will depend on the facts and circumstances existing at the time.

For these purposes, "person" means any individual, corporation, partnership, limited liability company, association, company, joint stock company, limited liability partnership, joint venture, trust or unincorporated organization, or any other entity whether or not a legal entity, or any governmental authority.

***Additional Covenants***

We have agreed under the Indenture, among other things:

- to maintain a place of payment;
- to maintain our corporate existence (subject to the provisions above relating to mergers and consolidations); and
- to deliver to the Trustee an annual officer's certificate with respect to our compliance with our obligations under the Indenture.

**Modification of the Indenture; Waiver**

We and the Trustee may, with the consent of the holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the Indenture, considered as one class, modify or amend the Indenture, including the provisions relating to the rights of the holders of senior notes of the affected series. However, no modification or amendment may, without the consent of each holder of affected senior notes:

- change the stated maturity of the principal of, or interest on, the senior note or reduce the principal amount or any premium payable on the senior note or reduce the interest rate of the senior note, or change the method of calculating the interest rate with respect to the senior note;
- reduce the amount of principal of any discount senior note that would be payable upon acceleration of the maturity of the senior note;
- change the coin, currency or other property in which the senior note or interest or premium on the senior note is payable;
- impair the right to institute suit for the enforcement of any payment on the senior note;
- reduce the percentage in principal amount of outstanding senior notes the consent of whose holders is required for modification or amendment of the Indenture or for waiver of compliance with certain provisions of the Indenture or for waiver of defaults;
- reduce the quorum or voting requirements applicable to holders of the senior notes; or
- modify the provisions of the Indenture with respect to modification and waiver, except as provided in the Indenture.

We and the Trustee may, without the consent of any holder of senior notes, modify and amend the Indenture for certain purposes, including to:

- add covenants or other provisions applicable to us and for the benefit of the holders of senior notes or one or more specified series thereof or to surrender any right or power conferred on us;
- cure any ambiguity or to correct or supplement any provision of the Indenture which may be defective or inconsistent with other provisions;
- make any other additions to, deletions from or changes to the provisions under the Indenture so long as the additions, deletions or changes do not materially adversely affect the holders of any series of senior notes in any material respect;
- change or eliminate any provision of the Indenture or add any new provision so long as the change, elimination or addition does not adversely affect the interests of holders of senior notes of any series in any material respect;

- change any place or places for payment or surrender of senior notes and where notices and demands to us may be served;
- provide for the issuance of registered senior notes in exchange for senior notes of the same series, which will have terms substantially identical in all material respects to such series of senior notes (except that the transfer restrictions contained in such series of senior notes will be modified or eliminated, as appropriate, and there will be no registration rights), and which will be treated, together with any outstanding senior notes of such series, as a single issue of securities;
- comply with any requirement in connection with the qualification of the Indenture under the 1939 Act; and
- comply with the rules of any applicable securities depository.

The holders of not less than a majority in aggregate principal amount of the senior notes of each affected series then outstanding under the Indenture, voting as a single class, may waive compliance by us with our covenant in respect of our corporate existence and the covenants described under “Restrictions on Liens and Sale and Leaseback Transactions” and “Consolidation, Merger, Conveyance or Other Transfer” and with the other covenants and restrictions provided in the Indenture. The holders of not less than a majority in aggregate principal amount of the senior notes outstanding may, on behalf of the holders of all of the senior notes, waive any past default under the Indenture and its consequences, except a default in the payment of the principal of or any premium or interest on any senior note and defaults in respect of a covenant or provision in the Indenture which cannot be modified, amended or waived without the consent of each holder of affected senior notes.

In order to determine whether the holders of the requisite principal amount of the outstanding senior notes have taken an action under the Indenture as of a specified date:

- the principal amount of a discount senior note that will be deemed to be outstanding will be the amount of the principal that would be due and payable as of that date upon acceleration of the maturity to that date; and
- senior notes owned by us or any other obligor upon the senior notes or any of our or their affiliates will be disregarded and deemed not to be outstanding.

**Events of Default**

An “event of default” means any of the following events which shall occur and be continuing:

- failure to pay interest on a senior note within 30 days after the interest becomes due and payable;
- failure to pay the principal of, or sinking fund payment or premium, if any, on, a senior note when due and payable;
- failure to perform or breach of any other covenant or warranty applicable to us in the Indenture continuing for 90 days after the Trustee gives us, or the holders of at least 33% in aggregate principal amount of the senior notes then outstanding give us and the Trustee, written notice specifying the default or breach and requiring us to remedy the default or breach, unless the Trustee or the Trustee and holders of a principal amount of senior notes not less than the principal amount of senior notes the holders of which gave that notice agree in writing to an extension of the period prior to its expiration;
- certain events of bankruptcy, insolvency or reorganization; and
- the occurrence of any event of default as defined in any mortgage, indenture or instrument under which there may be issued, or by which there may be secured or evidenced, any of our debt, whether the debt existed on the Restricted Notes Issue Date or is thereafter created, if the event of default: (i) is caused by a failure to pay principal after final maturity of the debt after the expiration of the grace period provided in the debt (which we refer to as a “payment default”) or (ii) results in the acceleration of the debt prior to its express maturity, and, in each case, the principal amount of the debt, together with the principal amount of any other debt under which there has been a payment default or the maturity of which has been so accelerated, aggregates $150 million or more.

The $150 million amount specified in the bullet point above shall be increased in any calendar year subsequent to 2017 by the same percentage increase in the urban CPI for the period commencing January 1, 2017 and ending on January 1 of the applicable calendar year. “Debt” for the purpose of the bullet point above means any debt of ours for money borrowed but, in each case, excluding liabilities in respect of capital lease obligations or swap agreements.

If the Trustee deems it to be in the interest of the holders of the senior notes, it may withhold notice of default, except defaults in the payment of principal of or interest or premium on or with respect to, any senior note.

If an event of default occurs and is continuing, the Trustee or the holders of not less than 33% in aggregate principal amount of the senior notes outstanding, considered as one class, may declare all principal due and payable immediately by notice in writing to us (and to the Trustee if given by holders); provided, however, that if an event of default occurs with respect to the specified events of bankruptcy, insolvency or reorganization, then the senior notes outstanding shall be due and payable immediately without further action by the Trustee or holders. If, after such a declaration of acceleration, we pay or deposit with the Trustee all overdue interest and principal and premium on senior notes that would have been due otherwise, plus any interest and other conditions specified in the Indenture have been satisfied before a judgment or decree for payment has been obtained by the Trustee as provided in the Indenture, the event or events of default giving rise to the acceleration will be deemed to have been waived and the declaration of acceleration and its consequences will be deemed to have been rescinded and annulled.

No holder of senior notes will have any right to enforce any remedy under the Indenture unless the holder has given the Trustee written notice of a continuing event of default, the holders of at least 33% in aggregate principal amount of the senior notes outstanding have requested the Trustee in writing to institute proceedings in respect of the event of default in its own name as Trustee under the Indenture and the holder or holders have offered the Trustee reasonable indemnity against costs, expenses and liabilities with respect to the request, the Trustee has failed to institute any proceeding within 60 days after receiving the notice from holders, and no direction inconsistent with the written request has been given to the Trustee during the 60-day period by holders of at least a majority in aggregate principal amount of senior notes then outstanding.

The Trustee is not required to risk its funds or to incur financial liability if there is a reasonable ground for believing that repayment to it or adequate indemnity against risk or liability is not reasonably assured.

If an event of default has occurred and is continuing, holders of not less than a majority in principal amount of the senior notes then outstanding generally may direct the time, method and place of conducting any proceedings for any remedy available to the Trustee, or exercising any trust or power conferred upon the Trustee; provided the direction could not involve the Trustee in personal liability where indemnity would not, in the Trustee’s sole discretion, be adequate.

**Satisfaction and Discharge**

Any senior note, or any portion of the principal amount thereof, will be deemed to have been paid for purposes of the Indenture, and our entire indebtedness in respect of the senior notes will be deemed to have been satisfied and discharged, if certain conditions are satisfied, including an irrevocable deposit with the Trustee or any paying agent (other than us) in trust of:

- money in an amount which will be sufficient; or
- in the case of a deposit made prior to the maturity of the senior notes or portions thereof, eligible obligations (as described below) which do not contain provisions permitting the redemption or other prepayment thereof at the option of the issuer thereof, the principal of and the interest on which when due, without any regard to reinvestment thereof, will provide monies which, together with the money, if any, deposited with or held by the Trustee or the paying agent, will be sufficient; or
- a combination of either of the two items described in the two preceding bullet points which will be sufficient;

to pay when due the principal of and premium, if any, and interest, if any, due and to become due on the senior notes or portions thereof.

This discharge of the senior notes through the deposit with the Trustee of cash or eligible obligations generally will be treated as a taxable disposition for U.S. federal income tax purposes by the holders of those senior notes. Holders of Restricted Notes who wishes to participate in the Exchange Offer should consult their own tax advisor as to the particular U.S. federal income tax consequences applicable to them in the event of such discharge.

For this purpose, "eligible obligations" for U.S. dollar-denominated senior notes, means securities that are direct obligations of, or obligations unconditionally guaranteed by, the United States, entitled to the benefit of the full faith and credit thereof, or depositary receipts issued by a bank as custodian with respect to these obligations or any specific interest or principal payments due in respect thereof held by the custodian for the account of the holder of a depositary receipt.

**Transfer and Exchange**

Subject to the terms of the Indenture, senior notes of any series may be exchanged for other senior notes of the same series of authorized denominations and of like aggregate principal amount and tenor. Subject to the terms of the Indenture and the limitations applicable to global securities, senior notes may be presented for exchange or registration of transfer at the office of the registrar without service charge, upon payment of any taxes and other governmental charges imposed on registration of transfer or exchange. Such transfer or exchange will be effected upon the Trustee, us or the registrar, as the case may be, being satisfied with the instruments of transfer.

If we provide for any redemption of a series of senior notes, we will not be required to execute, register the transfer of or exchange any senior note of that series for 15 days before a notice of redemption is mailed or register the transfer of or exchange any senior note selected for redemption.

**Trustees, Paying Agents and Registrars for the Senior Notes**

The Bank of New York Mellon Trust Company, N.A. will act as the Trustee, paying agent and registrar under the Indenture. We may change either the paying agent or registrar without prior notice to the holders of the senior notes, and we may act as paying agent. We and our affiliates maintain ordinary banking and trust relationships with a number of banks and trust companies, including The Bank of New York Mellon Trust Company, N.A.

**Governing Law**

The Indenture is, and the Exchange Notes will be, governed by New York law.

## BOOK-ENTRY, DELIVERY AND FORM

We have obtained the information in this section concerning The Depository Trust Company ("DTC"), Clearstream Banking, S.A., Luxembourg ("Clearstream") and Euroclear Bank S.A./N.V., as operator of the Euroclear System ("Euroclear") and their book-entry systems and procedures from sources that we believe to be reliable. We take no responsibility for an accurate portrayal of this information. In addition, the description of the clearing systems in this section reflects our understanding of the rules and procedures of DTC, Clearstream and Euroclear as they are currently in effect. Those systems could change their rules and procedures at any time.

The Exchange Notes will initially be represented by one or more fully registered global notes (each, a "Global Note" and collectively, the "Global Notes"). Each such Global Note will be deposited with, or on behalf of, DTC or any successor thereto and registered in the name of Cede & Co. (DTC's nominee). You may hold your interests in the Global Notes in the United States through DTC, or in Europe through Clearstream or Euroclear, either as a participant in such systems or indirectly through organizations which are participants in such systems. Clearstream and Euroclear will hold interests in the Global Notes on behalf of their respective participating organizations or customers through customers' securities accounts in Clearstream's or Euroclear's names on the books of their respective depositaries, which in turn will hold those positions in customers' securities accounts in the depositaries' names on the books of DTC.

So long as DTC or its nominee is the registered owner of the global securities representing the Exchange Notes, DTC or such nominee will be considered the sole owner and holder of the notes for all purposes of the Exchange Notes and the Indenture. Except as provided below, owners of beneficial interests in the Exchange Notes will not be entitled to have the Exchange Notes registered in their names, will not receive or be entitled to receive physical delivery of the Exchange Notes in definitive form and will not be considered the owners or holders of the Exchange Notes under the Indenture, including for purposes of receiving any reports delivered by us or the Trustee pursuant to the Indenture. Accordingly, each person owning a beneficial interest in an Exchange Note must rely on the procedures of DTC or its nominee and, if such person is not a participant, on the procedures of the participant through which such person owns its interest, in order to exercise any rights of a holder of Exchange Notes.

Unless and until we issue the Exchange Notes in fully certificated, registered form under the limited circumstances described below under the heading "-Certificated Notes":

- you will not be entitled to receive a certificate representing your interest in the Exchange Notes;
- all references in this prospectus to actions by holders will refer to actions taken by DTC upon instructions from its direct participants; and
- all references in this prospectus to payments and notices to holders will refer to payments and notices to DTC or Cede & Co., as the registered holder of the Exchange Notes, for distribution to you in accordance with DTC procedures.

**Book-Entry Procedures for the Global Notes**

All interests in the Global Notes will be subject to the operations and procedures of DTC, Clearstream or Euroclear, as applicable. We provide the following summaries of those operations and procedures solely for the convenience of investors. The operations and procedures of each settlement system are controlled by that settlement system and may be changed at any time. We are not responsible for those operations or procedures.

DTC has advised us that it is:

- a limited purpose trust company organized under the laws of the State of New York;
- a "banking organization" within the meaning of the New York State Banking Law;
- a member of the Federal Reserve System;
- a "clearing corporation" within the meaning of the New York State Uniform Commercial Code; and

- a “clearing agency” registered under Section 17A of the Exchange Act.

DTC was created to hold securities for its participants and to facilitate the clearance and settlement of securities transactions between its participants through electronic book-entry changes to the accounts of its participants. DTC’s participants include securities brokers and dealers, banks and trust companies, clearing corporations and other organizations. Indirect access to DTC’s system is also available to others such as banks, brokers, dealers and trust companies; these indirect participants clear through or maintain a custodial relationship with a DTC participant, either directly or indirectly. Investors who are not DTC participants may beneficially own securities held by or on behalf of DTC only through DTC participants or indirect participants in DTC.

So long as DTC’s nominee is the registered owner of a Global Note, that nominee will be considered the sole owner or holder of the Exchange Notes represented by that Global Note for all purposes under the Indenture. Except as provided below, owners of beneficial interests in a Global Note:

- will not be entitled to have Exchange Notes represented by the Global Note registered in their names;

- will not receive or be entitled to receive physical, certificated Exchange Notes; and

- will not be considered the owners or holders of the Exchange Notes under the Indenture for any purpose, including with respect to the giving of any direction, instruction or approval to the Trustee under the Indenture.

As a result, each investor who owns a beneficial interest in a Global Note must rely on the procedures of DTC to exercise any rights of a holder of Exchange Notes under the Indenture (and, if the investor is not a participant or an indirect participant in DTC, on the procedures of the DTC participant through which the investor owns its interest).

Redemption notices will be sent to DTC or its nominee. If less than all of the securities of a particular series are being redeemed, DTC’s practice is to determine by lot the amount of the interest of each direct participant in such issue to be redeemed.

In any case where a vote may be required with respect to securities of a particular series, neither DTC nor Cede & Co. (nor any other DTC nominee) will give consents for or vote the Global Notes, unless authorized by a direct participant in accordance with DTC’s procedures. Under its usual procedures, DTC will mail an omnibus proxy to us as soon as possible after the record date. The omnibus proxy assigns the consenting or voting rights of Cede & Co. to those direct participants to whose accounts the securities of such series are credited on the record date identified in a listing attached to the omnibus proxy.

Payments of principal, premium (if any) and interest with respect to the Exchange Notes represented by a Global Note will be made by the Trustee to DTC’s nominee as the registered holder of the Global Note. Neither we nor the Trustee will have any responsibility or liability for the payment of amounts to owners of beneficial interests in a Global Note, for any aspect of the records relating to or payments made on account of those interests by DTC, or for maintaining, supervising or reviewing any records of DTC relating to those interests.

Payments by participants and indirect participants in DTC to the owners of beneficial interests in a Global Note will be governed by standing instructions and customary industry practice and will be the responsibility of those participants or indirect participants and DTC.

Transfers between participants in DTC will be effected under DTC’s procedures and will be settled in same-day funds. Transfers between participants in Clearstream or Euroclear will be effected in the ordinary way under the rules and operating procedures of those systems.

Cross-market transfers between DTC participants, on the one hand, and Clearstream or Euroclear participants, on the other hand, will be effected within DTC through the DTC participants that are acting as depositaries for Clearstream and Euroclear. To deliver or receive an interest in a Global Note held in a Clearstream or Euroclear account, an investor must send transfer instructions to Clearstream or Euroclear, as the case may be, under the rules and procedures of that system and within the established deadlines of that system. If the transaction meets its settlement requirements, Clearstream or Euroclear, as the case may be, will send instructions to its DTC depositary to take action to effect final settlement by delivering or receiving interests in the relevant Global Notes in DTC, and making or receiving payment under normal procedures for same-day funds settlement applicable to DTC. Clearstream and Euroclear participants may not deliver instructions directly to the DTC depositaries that are acting for Clearstream or Euroclear.

Because of time zone differences, the securities account of a Clearstream or Euroclear participant that purchases an interest in a Global Note from a DTC participant will be credited on the business day for Clearstream or Euroclear immediately following the DTC settlement date. Cash received in Clearstream or Euroclear from the sale of an interest in a Global Note to a DTC participant will be received with value on the DTC settlement date but will be available in the relevant Clearstream or Euroclear cash account as of the business day for Clearstream or Euroclear following the DTC settlement date.

DTC, Clearstream and Euroclear have agreed to the above procedures to facilitate transfers of interests in the Global Notes among participants in those settlement systems. However, the settlement systems are not obligated to perform these procedures and may discontinue or change these procedures at any time. Neither we nor the Trustee will have any responsibility for the performance by DTC, Clearstream or Euroclear or their participants or indirect participants of their obligations under the rules and procedures governing their operations.

The laws of some jurisdictions may require that some purchasers of securities take physical delivery of securities in definitive form. Those laws may impair the ability to transfer or pledge beneficial interests in securities.

DTC may discontinue providing its services as securities depository with respect to the securities at any time by giving us reasonable notice. Under such circumstances, in the event that a successor securities depository is not obtained, certificates representing the securities are required to be printed and delivered. Also, we may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository), in which event, certificates representing the securities will be printed and delivered to DTC.

We have obtained the information in this section and elsewhere in this prospectus concerning DTC and DTC's book-entry system from sources that are believed to be reliable, but we take no responsibility for the accuracy of this information.

**Certificated Notes**

Exchange Notes in physical, certificated form will be issued and delivered to each person that DTC identifies as a beneficial owner of the related Exchange Notes only if:

- DTC notifies us at any time that it is unwilling or unable to continue as depositary for the Global Notes and a successor depositary is not appointed within 90 days;
- DTC ceases to be registered as a clearing agency under the Exchange Act and a successor depositary is not appointed within 90 days;
- we, at our option, notify the trustee that we elect to cause the issuance of certificated Exchange Notes; or
- certain other events provided in the Indenture should occur.

## MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

The following is a discussion of material U.S. federal income tax consequences applicable to a U.S. Holder (as defined below) of the Restricted Notes relating to the exchange of the Restricted Notes for the Exchange Notes.

This discussion is based on laws, regulations, rulings and decisions now in effect, all of which are subject to change, possibly with retroactive effect, or to differing interpretations. This discussion does not address the tax considerations arising under the U.S. federal estate and gift tax laws or the laws of any non-U.S., state or local jurisdiction. In addition, this summary does not discuss all aspects of U.S. federal income taxation that may be relevant to a particular holder or to certain types of holders that may be subject to special tax rules (such as banks, tax-exempt entities, insurance companies, regulated investment companies, S corporations, persons who are subject to the alternative minimum tax, dealers in securities or currencies, traders in securities electing to mark to market, U.S. expatriates, persons that hold the Exchange Notes or the Restricted Notes as a position in a “straddle” or conversion transaction, or as part of a “synthetic security” or other integrated financial transaction, U.S. Holders (as defined below) that have a “functional currency” other than the U.S. dollar, U.S. Holders that hold the Exchange Notes or Restricted Notes through a non-U.S. broker or other intermediary or persons required to recognize any item of gross income for U.S. federal income tax purposes with respect to the Exchange Notes or the Restricted Notes no later than when such item is taken into account on an applicable financial statement). In addition, this summary is limited to holders who hold the Restricted Notes and Exchange Notes as “capital assets” within the meaning of section 1221 of the Code.

For purposes of the following discussion, a “U.S. Holder” means a beneficial owner of the Restricted Notes or Exchange Notes that for U.S. federal income tax purposes is (i) an individual who is a citizen or resident of the United States; (ii) a corporation (or any other entity taxed as a corporation) created or organized in or under the laws of the United States, any state thereof, or the District of Columbia; (iii) an estate the income of which is subject to U.S. federal income taxation regardless of its source; or (iv) in general, a trust if (a) it is subject to the primary supervision of a court within the United States and one or more “United States persons”, as described in Section 7701(a)(30) of the Code, have the authority to control all of the substantial decisions of the trust or (b) it has a valid election in effect under applicable Treasury regulations to be treated as a United States person.

The exchange of a Restricted Note for an Exchange Note pursuant to the Exchange Offer generally will not constitute a taxable exchange for U.S. federal income tax purposes and, accordingly, the Exchange Note received will be treated as a continuation of the Restricted Note in the hands of such U.S. Holder. As a result, there will be no U.S. federal income tax consequences to a U.S. Holder who exchanges a Restricted Note for an Exchange Note pursuant to the Exchange Offer, and any such holder will have the same adjusted tax basis and holding period in the Exchange Note as it had in the Restricted Note immediately before the exchange. A U.S. Holder who does not exchange its Restricted Note for an Exchange Note pursuant to the Exchange Offer will not recognize any gain or loss, for U.S. federal income tax purposes, upon consummation of the Exchange Offer.

***Please consult your own tax advisor regarding the U.S. federal, state, local, and non-U.S. and other tax considerations of the acquisition, ownership, and disposition of the Exchange Notes. Additionally, please consult your own tax advisor concerning the exchange of a Restricted Note for an Exchange Note pursuant to the Exchange Offer in light of your particular circumstances.***

## PLAN OF DISTRIBUTION

Each broker-dealer that receives the Exchange Notes for its own account pursuant to the Exchange Offer must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of such Exchange Notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the Exchange Notes received in exchange for the Restricted Notes where such Restricted Notes were acquired as a result of market-making activities or other trading activities. Each such broker-dealer, through its participation in the Exchange Offer, will be deemed to have confirmed to us that it has not entered into any agreement or understanding with us or any of our "affiliates", as defined in Rule 405 under the Securities Act, to participate in a "distribution", as defined in the Securities Act, of the Exchange Notes.

We have agreed that, starting on the Expiration Date and ending 30 days after the Expiration Date, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale.

The Company will not receive any proceeds from any sale of the Exchange Notes by broker-dealers. The Exchange Notes received by broker-dealers for their own account pursuant to the Exchange Offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the Exchange Notes or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such Exchange Notes. Any broker-dealer that resells the Exchange Notes that were received by it for its own account pursuant to the Exchange Offer and any broker or dealer that participates in a "distribution", as defined in the Securities Act, of such Exchange Notes may be deemed to be an "underwriter" within the meaning of the Securities Act and any profit on any such resale of the Exchange Notes and any commission or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The Letter of Transmittal states that, by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act.

For a period of 30 days after the completion of the Exchange Offer, we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents.

**Prohibition of Sales to EEA Retail Investors**

The Exchange Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the European Economic Area ("EEA"). For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of Directive 2014/65/EU (as amended, "MiFID II"); or (ii) a customer within the meaning of Directive 2002/92/EC (as amended, the "Insurance Mediation Directive"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; or (iii) a purchaser that is not a qualified investor as defined in Directive 2003/71/EC (as amended, the "Prospectus Directive"). Consequently, no key information document required by Regulation (EU) No 1286/2014 (as amended, the "PRIIPs Regulation") for offering or selling the Exchange Notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering or selling the Exchange Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation.

## LEGAL MATTERS

The validity of the Exchange Notes to be offered by Pacific Gas and Electric Company will be passed upon for us by Cravath, Swaine & Moore LLP, New York, New York (with respect to New York law) and Hunton Andrews Kurth LLP (with respect to California law).

## EXPERTS

The consolidated financial statements, and the related consolidated financial statement schedule, incorporated in this Prospectus by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 2017, and the effectiveness of the Company and its subsidiaries' internal control over financial reporting have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their reports, which are incorporated herein by reference (which reports (1) express an unqualified opinion on the consolidated financial statements and consolidated financial statement schedule and include an Emphasis of Matter paragraph referring to the Northern California wildfires that occurred in October 2017 that may result in material losses or penalties to the Company and (2) express an unqualified opinion on the effectiveness of internal control over financial reporting). Such consolidated financial statements and consolidated financial statement schedule have been so incorporated in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

# Pacific Gas and Electric Company

**OFFER TO EXCHANGE**

**Up to $500,000,000 aggregate principal amount of our outstanding Floating Rate Senior Notes due November 28, 2018, $1,150,000,000 aggregate principal amount of our outstanding 3.30% Senior Notes due December 1, 2027 and $850,000,000 aggregate principal amount of our outstanding 3.95% Senior Notes due December 1, 2047 that were issued in a private offering on November 29, 2017, for a like aggregate principal amount of Floating Rate Senior Notes due November 28, 2018, 3.30% Senior Notes due December 1, 2027 and 3.95% Senior Notes due December 1, 2047, respectively, in a transaction registered under the Securities Act of 1933, as amended.**

**PROSPECTUS**

**Dated April 13, 2018**

# Exhibit 23

**March 29, 2023**

**Form ADV Part 2A**

**The Baupost Group, L.L.C.**

**10 St. James Ave. Suite 1700**

**Boston, MA 02116**

**Telephone: (617) 210-8300**

**www.baupost.com**

**This brochure (the "Brochure") provides information about the qualifications and business practices of The Baupost Group, L.L.C. If you have any questions about the contents of this brochure, please contact us at 617-210-8300. The information in this Brochure has not been approved or verified by the United States Securities and Exchange Commission (the "SEC") or by any state securities authority.**

**Additional information about The Baupost Group, L.L.C. is also available on the SEC's website at www.adviserinfo.sec.gov.**

**Registration as a registered investment adviser pursuant to the Investment Advisers Act of 1940, as amended (the "Advisers Act"), does not imply a certain level of skill or training.**

**Item 2. Material Changes**

There have been no material changes since the prior annual amendment filing dated March 29, 2022.

**Item 3. Table of Contents**

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## Item 4. Advisory Business

The Baupost Group, L.L.C. ("Baupost") was formed in May 1982 (originally as The Baupost Group, Inc.). Baupost is headquartered in Boston, Massachusetts. Baupost's Chief Executive Officer and principal owner, Seth A. Klarman, serves as Portfolio Manager and has been managing the investments of Baupost's clients since the company's inception. Baupost is the managing general partner to eleven domestic investment limited partnerships (each, a "Partnership," collectively, the "Baupost Partnerships"). All of the Baupost Partnerships are privately offered investment vehicles exempt from registration as investment companies under the Investment Company Act of 1940, as amended (the "1940 Act"). Baupost Partners, L.L.C. ("Baupost Partners"), an affiliate of Baupost, serves as profit sharing general partner to the Baupost Partnerships (together with Baupost, the "General Partners"). Baupost has no ownership interest in Baupost Partners, but certain indirect owners and employees of Baupost are members of Baupost Partners.

As managing general partner of each Partnership, Baupost is solely responsible for the management and administration of such Partnership, including the making of all investment decisions on behalf of such Partnership and the placing of all orders for the purchase and sale of investments.

Baupost manages each Partnership pursuant to the investment strategy set forth in such Partnership's limited partnership agreement ("LP Agreement") and, if applicable, offering memorandum. The Baupost Partnerships invest in a wide range of public and private securities and assets. Baupost does not provide specifically tailored investment advice to investors in the Baupost Partnerships, and investors may not impose investment restrictions on their investments in the Baupost Partnerships.

Contributions to and withdrawals from the Baupost Partnerships are subject to the terms and conditions set forth in the respective LP Agreements of the Baupost Partnerships in which investors are invested. Investors in the Baupost Partnerships are subject to restrictions on their ability to withdraw capital from the Baupost Partnerships. Baupost has the right, in its sole discretion, to waive or alter some or all of the applicable restrictions on capital withdrawals and contributions (for example, notice periods, withdrawal of the portion of capital allocated to restricted investments (which are generally illiquid investments designated as restricted investments in the judgment of Baupost pursuant to certain of the LP Agreements), and other matters) or on transfers of limited partnership interests for investors as set forth in each Partnership's LP Agreement and, if applicable, offering memorandum, and Baupost generally does waive notice periods for employees and certain former employees.

The Baupost Partnerships indirectly own a platform of affiliated entities located in Luxembourg to facilitate investment in European real estate and related assets (the "European Investment Platform"). In 2019, the European Investment Platform established an entity that will provide accounting, administrative, legal and corporate secretarial support services, and may also provide other support services, to certain Luxembourg investment vehicles in which the Baupost Partnerships indirectly invest.

Investors are urged to review the relevant LP Agreement and, if applicable, offering memorandum for additional information about matters addressed in this and other items throughout this Brochure.

As of December 31, 2022, Baupost's regulatory assets under management were approximately $27,384,539,075, all of which are managed on a discretionary basis. Baupost does not manage assets on a non-discretionary basis.

**Item 5. Fees and Compensation**

As compensation for its advisory services, Baupost receives a management fee from each of the Baupost Partnerships that is required to be paid in advance at the beginning of each quarter. The management fee is assessed based on relevant investor capital account balance as of the first business day of each fiscal quarter, taking into account capital contributions or withdrawals as of such date. Prior to applying the management fee rate, each capital account balance is reduced (but not below zero) by unrealized gains (net of unrealized losses) on any Illiquid Asset (generally as defined in each Partnership's LP Agreement)[1] and reduced (but not below zero) by any positive adjusted profit sharing obligation allocated to such capital account. The management fee for a fiscal quarter is due and payable upon calculation. The management fee expense is evenly amortized over the quarter and deducted from each relevant investor's capital account monthly.

In addition, the General Partner(s) are eligible to receive performance-based compensation from the Baupost Partnerships, subject to, if applicable, loss carryforward limitations set forth in each LP Agreement. As a result of the profit sharing obligation, a certain portion of eligible profits initially allocated to each relevant investor in each Partnership is reallocated to the General Partner(s), subject to the limitations set forth in each applicable LP Agreement. The profit sharing obligation is accrued at least quarterly and is reallocated to the General Partner(s) annually. If an investor fully or partially withdraws or transfers its interest during the year, a proportionate amount of the profit sharing obligation may be, or in the case of withdrawals, generally will be reallocated from the capital account of the investor to the capital account of the General Partner(s).

[1] Certain Partnerships' LP Agreements use the defined term "Illiquid Investment" – with respect to those Partnerships, the term Illiquid Asset as used herein shall have the meaning given to the term Illiquid Investment in such LP Agreements.

The profit sharing obligation of each relevant investor in the Baupost Partnerships is 20% of eligible profits, as described in detail in each respective LP Agreement and, if applicable, offering memorandum. Any profit sharing obligation generated from unrealized gains (net of unrealized losses) on any Illiquid Asset will be deferred for reallocation to the General Partner(s) until gains are realized except in the case of a full withdrawal of an investor's capital balance.

Management fees and profit sharing obligations are non-negotiable and non-refundable; however, Baupost may, in its sole discretion, waive these fees and/or obligations for certain investors in whole or in part. Baupost generally waives management fees and/or profit sharing obligations for current employees, certain former employees, founders and certain related parties of the foregoing, including foundations related to such persons. Baupost may discontinue fee and/or profit sharing obligation waivers at any time, and Baupost generally discontinues fee and profit sharing obligation waivers for most departing employees. However, Baupost does not expect to discontinue fee or profit sharing obligation waivers for foundations of employees.

The aforementioned compensation of the General Partners is based upon the value of the Baupost Partnerships' assets, which Baupost is responsible for determining. To mitigate this conflict, Baupost does not collect management fees on unrealized gains (net of unrealized losses) on any Illiquid Asset and does not impose a profit sharing obligation on unrealized gains (net of unrealized losses) on any Illiquid Asset except in the case of a full withdrawal of an investor's capital balance. Additionally, Baupost engages independent third parties to assist with valuing certain Illiquid Assets. Baupost also engages an independent auditor to perform an annual audit of the Baupost Partnerships in conformity with accounting principles generally accepted in the United States ("GAAP") at each calendar year-end.

**Expenses**

Baupost will, in consideration for management fees, bear its own overhead expenses incurred in connection with managing the affairs and business of the Baupost Partnerships, including expenses related to its office space, utilities, and employees (i.e., those persons participating in its payroll and those Baupost deems to be its employees), and all costs and expenses of travel undertaken by Baupost employees, including travel to perform due diligence related to acquiring prospective investments or to perform ongoing supervision of the Baupost Partnerships' assets.

The Baupost Partnerships will bear, or reimburse Baupost for, all organizational, restructuring and offering expenses and all ordinary and extraordinary expenses incurred or advanced in the operation or management of the Baupost Partnerships and their investment activities as Baupost deems to be reasonable and necessary. The costs and expenses borne directly or indirectly through affiliated entities (e.g., special purpose vehicles) by the Baupost Partnerships (of which the investors bear their allocable share) include, without limitation:

(i) Investment-related expenses, such as expenses related to sourcing investments, performing due diligence related to prospective investments or areas of investment, structuring, negotiating and executing acquisitions and dispositions of investments and performing ongoing supervision and maintenance of investments, including but not limited to the following:

a) brokerage fees and commissions;
b) clearing and settlement charges and custodial and sub-custodial fees;
c) fees and expenses (including travel expenses) charged by professional service providers (some of whom may be former employees of, or current or former consultants to, Baupost), such as legal, accounting, auditing, consulting (which may include the cost of consultants onsite at Baupost's offices), investment banking, research (including expert network services and research provided by providers of brokerage services), class action monitoring and recovery (which may be in the form of a fixed fee or based on a percentage of the amount recovered by a Partnership in respect of such litigation, or a combination of both), advisory, lobbyist and other professional service providers;
d) costs of retainers and transaction-based compensation or success fees, some of which may be discretionary, charged by third party consultants, operating partners, brokers, market participants and advisers (some of whom may be former employees of, or current or former consultants to, Baupost) in connection with sourcing or evaluating investments, any of which may be fixed or based on a percentage of the proceeds of sourced investments, a percentage of the amount invested, or a combination of the foregoing;
e) management, development, profit-sharing or other fees or expenses (including, in certain instances, an operating partner's operational and overhead expenses) charged by operating partners or third parties (some of whom may be former employees of, or current or former consultants to, Baupost) who manage certain investments (including joint ventures, investment companies, partnerships and other pooled investment vehicles), any of which such fees or expenses may be fixed or based on a percentage of the proceeds of managed investments or a percentage of the amount invested, or a combination of the foregoing;
f) fees and expenses associated with the organization, operation and maintenance of special-purpose and other investment vehicles, including aggregating vehicles and service-providing vehicles including the European Investment Platform, used in connection with the Baupost Partnerships' investments, including (w) operational and overhead expenses such as office rent, furniture, build-out costs, personnel costs and information technology costs, (x) fees and expenses associated with developing, structuring, and winding up such entities, (y) costs of management of assets, including real property investments, owned by the Baupost Partnerships and (z) legal, accounting, and operational support;

g) fees and expenses associated with any advisory board or committee required or advisable in certain non-U.S. jurisdictions in connection with investments;
h) interest and fees (including, without limitation, commitment, structuring, and underwriting fees) on margin loans, loan facilities, total return swaps and other indebtedness or other types of instruments, and related fees and expenses;
i) any of the foregoing to the extent related to potential investments that were not consummated; and
j) any other expenses related to a prospective investment, an existing investment or a type of investment;

(ii) fees and expenses of professional service providers, including, without limitation, consultants and attorneys, including expenses for legal work related to Baupost Partnerships' amendments, costs and expenses incurred in connection with the dissolution, winding up, termination and liquidation of the Baupost Partnerships and the costs of any litigation or investigation involving activities of the Baupost Partnerships;

(iii) expenses related to (x) the Baupost Partnerships' indemnification obligations under the LP Agreements, (y) director and officer liability insurance and errors and omissions liability insurance, including, without limitation, insurance that also provides coverage to the General Partners and their affiliates, officers and employees, for indemnifiable and non-indemnifiable fees, expenses and losses and (z) other insurance costs including insurance of which the General Partners and their affiliates are beneficiaries (including, for example, costs associated with fund management and employment practices liability insurance, cyber risk insurance and financial institution bond and STAMP bond coverage);

(iv) administration fees and other expenses charged by or relating to the services of third-party providers of administration services;

(v) expenses associated with pricing and investment valuation services, including the costs of third-party vendors such as valuation and pricing vendors (e.g., Bloomberg, Markit, etc.);

(vi) audit, accountant and tax preparation expenses;

(vii) fees and expenses related to compliance with the rules of any self-regulatory organization or applicable law or regulation in connection with the activities of the Partnership, including, without limitation, any governmental, regulatory, licensing, filing or registration fees or taxes (including, without limitation, fees and expenses incurred in connection with the preparation and filing of Section 13 filings, Section 16 filings and other similar regulatory filings);

(viii) costs associated with compliance with (x) anti-money laundering regulations, (y) know your customer and anti-money laundering requirements of service providers and other counterparties and (z) the Baupost Partnerships' know your customer review of prospective and existing investors, service providers and other counterparties; and

(ix) other expenses associated with the operation of the Baupost Partnerships (these may include, for example, although not historically borne by the Baupost Partnerships, expenses associated with organizing and conducting investor meetings).

As stated above, the Baupost Partnerships will incur brokerage and other transactions costs when a broker-dealer is used in connection with an investment. For additional information regarding brokerage practices, please see Item 12 below.

When a Baupost Partnership invests in joint ventures, including those with operating partners, or pooled investment vehicles, investors bear the cost of any management and performance fees of such third parties in addition to the fees of the General Partners.

Under the circumstances set forth in the LP Agreements, certain tax-related expenses or regulatory expenses may be specially allocated by Baupost to the accounts of those investors to which the relevant expenses are attributable.

Certain expenses may be borne in part by the Baupost Partnerships and in part by Baupost, such as in circumstances when a consultant provides services for the benefit of Baupost and other services for the benefit of the Baupost Partnerships or a specific Partnership investment.

The organizational and operating expenses of the European Investment Platform are borne by investors who participate in restricted investments.

To the extent that any expenses or fees relate to all or some of the Baupost Partnerships (or to investments thereof), such expenses or fees are allocated on a pro rata basis across the Baupost Partnerships to align, as closely as practicable, the expense burden with the beneficiaries of the service or investment activity. To make such allocation determinations, Baupost exercises its judgment based on the information available at that time; Baupost may, in its sole discretion, reassess such determinations and reallocate certain expenses if circumstances warrant.

The Baupost Partnerships that would have participated in a terminated or abandoned transaction also bear expenses in connection with such terminated or abandoned transaction.

## Item 6. Performance-Based Fees and Side-By-Side Management

As described in Item 5 ("Fees and Compensation"), the General Partner(s) are eligible to receive performance-based compensation from the Baupost Partnerships. Baupost recognizes that managing partnerships with differing terms relating to performance-based fees (such as different loss carryforward limitations) presents potential conflicts of interest, including that Baupost may have an incentive to favor one Partnership over another when allocating investment opportunities. To mitigate these conflicts, Baupost's policies and procedures seek to provide that investment personnel make decisions based on the best interests of the Baupost Partnerships, without consideration of Baupost's financial interests. Baupost's Trade Allocation Policy seeks to allocate

investments to the Baupost Partnerships in a fair and equitable manner. Please see Item 11 for additional detail on Baupost's Trade Allocation Policy.

## Item 7. Types of Clients

Baupost's clients are the Baupost Partnerships. Baupost manages one Partnership exempt from registration under Section 3(c)(1) of the 1940 Act and ten Partnerships exempt from registration under Section 3(c)(7) of the 1940 Act. Investors, which generally include high-net-worth individuals, corporations, charitable institutions, pension and profit sharing plans, trusts, individual retirement accounts and other entities, are admitted to the Baupost Partnerships at the discretion of Baupost, and contributions by investors to the Baupost Partnerships are accepted solely at the discretion of Baupost. Baupost also allows certain of its employees to invest in certain Baupost Partnerships. Certain Baupost Partnerships impose a minimum initial investment requirement of up to $10 million, which may be waived at the discretion of Baupost.

## Item 8. Methods of Analysis, Investment Strategies and Risk of Loss

Baupost is an opportunistic, value-oriented, open mandate investment organization whose goal is to invest capital in such a manner as to achieve attractive risk-adjusted returns over an extended period of time. To achieve this objective, the Baupost Partnerships seek to invest in assets that Baupost considers to be undervalued relative to their market price. The Baupost Partnerships seek to invest, either directly or indirectly, in securities and other assets that Baupost believes to have some or all of the following characteristics: they are currently out of favor, but have good prospects; they sell at a significant discount to underlying economic value; they have catalysts in place for the realization of underlying value; they are highly complex; they are somewhat or highly illiquid and they sell at prices below what would reasonably be expected due to market imperfections and inefficiencies, including but not limited to temporary supply/demand imbalances, information gaps, and selling pressures.

The Baupost Partnerships have a broad investment mandate that contemplates investing in a range of financial instruments, asset classes and geographic regions, including those with respect to which Baupost initially may have limited experience. An investment in the Baupost Partnerships entails various risks, including the speculative nature of the Baupost Partnerships' activities; the illiquidity of interests in the Baupost Partnerships; the illiquidity of certain investments the Baupost Partnerships may make and the risk that the securities markets may continue indefinitely to undervalue the Baupost Partnerships' investments or that the investments may fail to appreciate as anticipated by Baupost.

The Baupost Partnerships may invest in, subscribe for, purchase or otherwise acquire and/or sell (including short sales) or otherwise dispose of securities and assets of all types, including, without limitation, stock (including preferred and convertible stock as well as common stock of any type), warrants, options, swaps, trade claims, bank debt (including undrawn revolvers), bonds, other debt

instruments including self-originated loans, currency, cryptocurrency and other digital assets, futures, derivatives, commodities, contract rights of any kind, royalty interests, non-U.S. securities and other assets (including assets in emerging markets), structured investment vehicles, secured and unsecured instruments, asset-backed securities, commercial and residential mortgage-backed securities, real estate and related instruments, other complex financial instruments and rights and distressed assets. The securities in which the Baupost Partnerships invest include securities that are listed or traded on domestic or non-U.S. exchanges or other trading networks (including over the counter markets), as well as securities that are unlisted and trade infrequently or not at all.

At times a significant amount of the Baupost Partnerships' investments may be in securities or other assets that are not freely tradable or are otherwise illiquid. Such investments include interests in private equity investments, venture capital investments, real estate, litigation investments, leveraged buy-out vehicles and joint ventures, which are typically organized as limited partnerships or limited liability companies, and are managed by third-party asset managers that specialize in the particular class of assets under management.

The Baupost Partnerships may also invest in private investments in public equity ("PIPEs"), which generally are not registered with the SEC until after a certain time period from the date the private sale is completed, special purpose acquisition companies, Rule 144A securities and direct assets such as car loans, consumer loans, commodities or non-performing assets.

Prospective investors should also consider the risks associated with the loss of key personnel of Baupost. Prospective investors should consult with their own advisers in order to understand the consequences of an investment in the Baupost Partnerships. Any investor not able to bear the risk of loss of his or her investment should not participate in the Baupost Partnerships.

Baupost selects investments according to many criteria, which may include book value, estimated underlying economic value, current and projected future earnings, cash flow, yield, skills of management, future prospects of the business and current market price of the investment. Baupost utilizes several analytical techniques, which may include fundamental analysis, analysis of historical relationships, economic analysis, business cycle analysis, interest rate analysis and industry analysis to make its investment decisions.

**Investment Risks**

The types of investments made by the Baupost Partnerships are subject to certain risks. The following risk factors do not purport to be a complete list or explanation of the risks involved in an investment in the Baupost Partnerships. Investors are advised to review the applicable Partnership's offering materials for a more extensive description of the risks of an investment in the Baupost Partnerships.

Speculative Investment Strategy

By its nature, all investing, including by the Baupost Partnerships, is speculative. Despite the Baupost Partnerships' operating history, there is no assurance that the Baupost Partnerships will achieve their investment objective. Baupost's assessment of the short-term or long-term prospects of investments may not prove accurate. No assurance can be given that any investment strategy implemented by Baupost on behalf of the Baupost Partnerships will be successful, and investors may suffer a significant loss of their invested capital. Past performance of the Baupost Partnerships is not indicative of future results, which may vary.

Broad Discretion

The Baupost Partnerships have a broad investment mandate that contemplates investing in a range of financial instruments, asset classes, and geographic regions, including those with respect to which Baupost initially may have limited experience.

Value Style

Baupost adheres to a value investment philosophy. As a result, there is a risk that the securities markets may continue indefinitely to undervalue the investments in the Baupost Partnerships' portfolios, or that the investments may fail to appreciate as anticipated by Baupost. This risk may be greater for investments in small and medium-sized companies, which could be more vulnerable to adverse developments and are less liquid to trade.

The Baupost Partnerships frequently invest in securities, industries and asset classes that are out of favor or ignored by other investors. Investors incur the risk that such a contrarian strategy may not succeed and, to the extent that adverse economic and investment trends continue for an extended time, that the Baupost Partnerships may not achieve their goals. Even if a Partnership's value-investment strategy is successful, there may be significant portfolio turnover and, consequently, high transaction costs.

Investment and Due Diligence Process

Before making investments, Baupost conducts due diligence that it deems reasonable and appropriate based on the facts and circumstances applicable to each investment. Such due diligence often includes complex business, financial, tax, accounting and legal issues. When conducting due diligence and making an assessment regarding an investment, Baupost will rely on the resources reasonably available to it, which in some circumstances, whether or not known to Baupost at the time, may not be sufficient, accurate, complete or reliable. Due diligence may not reveal or highlight matters that could have a material adverse effect on the value of an investment.

Control of Portfolio Investments

The Baupost Partnerships may seek to influence or control management of various issuers. This activity may include investing in a potential takeover, leveraged buy-out or reorganization or otherwise by investing in public or private companies, including other entities that were organized in order to purchase securities for the purpose of influencing or controlling management. In addition, such investments may be structured in a manner that permits the Baupost Partnerships to have some input into the management of the vehicle by an operating partner or third party asset manager.

For example, when making investments in companies, the Baupost Partnerships may also seek to influence or control management by, for example, discussing formally or informally with management different operating strategies, proposing shareholder resolutions, engaging in a proxy contest, serving on a board of directors, holding board of directors observer rights or serving on a creditors' committee established in connection with a company's insolvency. The success of an investment predicated on the ability of the Baupost Partnerships to influence or control management depends upon, among other things, (i) Baupost's ability to properly identify companies whose securities' prices can be improved through corporate and/or strategic action; (ii) the Baupost Partnerships' ability to acquire sufficient securities of such companies at a sufficiently attractive price; (iii) the Baupost Partnerships' ability to build their position in accordance with applicable regulations; (iv) the willingness of the management of such companies and other security holders to respond positively to Baupost's proposals and (v) favorable movements in the market price of any such company's securities in response to any actions taken by such company. There can be no assurance that any of the foregoing will occur.

Although the Baupost Partnerships generally do not seek controlling positions in public companies, if the Baupost Partnerships acquire beneficial ownership of more than 10% of a certain class of securities of a public company or places a director or observer on the board of directors of such a company, under Section 16 of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"), the Baupost Partnerships may be subject to certain additional requirements and limitations. Furthermore, when the Baupost Partnerships' ownership of an issuer's securities exceeds certain thresholds, the Baupost Partnerships may be limited in their ability to engage in certain transactions, including taking certain short positions and making certain investments in or with respect to companies that compete with the issuer. Similar requirements and limitations may apply in non-U.S. jurisdictions.

As noted herein, the Baupost Partnerships, acting either alone or as part of a group, may acquire a "control" position in an issuer's securities or place an employee as a member or an observer of the board of directors of such issuer. This may subject the Baupost Partnerships to additional risks of liability for environmental damage, product defects, failure to supervise management, violation of governmental regulations and other types of liability in which the limited liability generally characteristic of business operations may be ignored. Additionally, to the extent that any Baupost

personnel incur liability for serving as a director of an issuer or otherwise serving on an ad hoc committee or other similar body, such liability generally will be borne by the relevant Baupost Partnerships.

Significant Positions in Securities; Regulatory Requirements

In the event the Baupost Partnerships acquire a significant stake in certain issuers of securities and such stake exceeds certain percentage or value limits, the Baupost Partnerships may be subject to regulation and regulatory oversight that may impose notification and filing requirements or other administrative burdens on the Baupost Partnerships and Baupost. Any such requirements may impose additional costs on the Baupost Partnerships and may delay the acquisition or disposition of the securities or the Baupost Partnerships' ability to respond in a timely manner to changes in the markets with respect to such securities.

In addition, "position limits" may be imposed by various regulators that may limit the Baupost Partnerships' ability to effect desired trades. For instance, the CFTC has adopted position limits on the size of positions that market participants may own or control in certain futures, options on futures and swaps. Position limits are the maximum amounts of gross, net long or net short positions that any one person or entity may own or control in a particular issuer's securities. All positions owned or controlled by the same person or entity, even if in different accounts, may be aggregated for purposes of determining whether the applicable position limits have been exceeded and often are aggregated for the Baupost Partnerships. To the extent that a Partnership's position limits were aggregated with the other Baupost Partnerships' position limits, the effect on that Partnership and resulting restriction on its investment activities may be significant. If at any time positions managed by Baupost were to exceed applicable position limits, Baupost would be required to liquidate positions held by one or more Partnerships, to the extent necessary to come within those limits. Further, to avoid exceeding any position limits, Baupost might have to forgo or modify certain of its contemplated trades for the Baupost Partnerships.

Moreover, the presence of corporate governance mechanisms such as staggered boards, poison pills and classes of stock with increased voting rights may hinder Baupost's ability to execute any corporate governance strategy successfully.

Follow-on Investments

The Baupost Partnerships have provided, and may in the future have the opportunity, or be called upon to provide, follow-on funding for certain portfolio investments ("Follow-on Investments"). Electing not to make a Follow-on Investment could have a substantial negative impact on an investment in need of capital, may diminish the Baupost Partnerships' ability to influence the investment's future development, may result in dilution of the Baupost Partnerships' investment itself and could impair the value of such investment and, in turn, the value of the Baupost Partnerships. If the Baupost Partnerships elect to make a Follow-on Investment, there is a risk that

the Follow-on Investment does not preserve, protect or enhance the existing investment, and the Baupost Partnerships may lose both their initial investment and the Follow-on Investment.

Concentration of Investments

It is expected that no single investment of a Partnership will exceed 10% of the assets of such Partnership at the time of purchase. However, the favorable performance of a particular investment or the sale or other disposition or relatively unfavorable performance of other investments may increase the percentage of such Partnership's assets in a single investment beyond 10%. In addition, Baupost reserves the right to acquire a single investment that exceeds 10% of the assets of any Partnership at the time of its purchase if it deems the investment advisable.

During times when the Baupost Partnerships invest their assets in a small number of issuers, or in a larger number of issuers but with significant concentration of assets in only a few, the fair value of the Baupost Partnerships' assets may fluctuate more widely than the fair value of a portfolio that invests in a greater number of issuers. This lack of diversification involves an increased risk of loss to the Baupost Partnerships if an issuer in which the Baupost Partnerships invest were unable to make interest or principal payments or if the market value of the issuer's securities were to decline.

Portfolio Turnover

Portfolio turnover is not a limiting factor with respect to investment decisions. High portfolio turnover involves correspondingly greater brokerage commissions and other transaction costs, which will be borne by the Baupost Partnerships. Alternatively, if portfolio turnover is relatively low, in order to obtain research services, the Baupost Partnerships may be subject to brokerage commissions for execution services higher than the commissions the Baupost Partnerships would otherwise pay if the Baupost Partnerships' trading volume were higher.

Cash Balances

The Baupost Partnerships typically hold significant cash or cash equivalent balances. The Baupost Partnerships generally hold any cash balances they may accumulate for investment, reinvestment and distribution to the Partners or reserves for unfunded obligations in short-term debt securities, either taxable or, in whole or in part, tax-exempt, in securities subject to repurchase agreements, in taxable or tax-exempt money market mutual funds or in bank accounts. These cash balances are typically held in securities issued by or backed by the government of the United States. The cash balances of the Baupost Partnerships (including amounts held in short-term debt securities, money market mutual funds or bank accounts) will vary from time to time as Baupost may deem advisable and may at any particular time amount to a significant portion of the assets of the Baupost Partnerships. Pending investment or reinvestment, such cash balances may not significantly appreciate in value and may be exposed to inflation risk.

Alternatively, Baupost may deem it advisable to hold low or no cash balances whatsoever from time to time.

Leverage and Guarantees

Baupost has not used leverage that is recourse to the Partnerships. However, the Baupost Partnerships do have the ability to utilize partnership-level leverage, including by trading on margin, short selling or writing options, or providing guarantees related to portfolio investments. Baupost regularly employs leverage on certain types of investments on a non-recourse or limited recourse basis. Although leverage increases returns if the Baupost Partnerships earn a greater return on the incremental investments purchased with borrowed funds than they pay for such funds, the use of leverage decreases returns if the Baupost Partnerships fail to earn as much on such incremental investments as they pay for such funds. The effect of leverage in a declining market would also result in a greater decrease in the Baupost Partnerships' Net Asset Value than if the Baupost Partnerships were not so leveraged. If any of the assets used to secure the borrowing decrease in value, the Baupost Partnerships may be required to pledge additional collateral to the lender in the form of cash or securities to avoid liquidation of those assets or potential liquidation of the leveraged asset.

The Baupost Partnerships have invested and expect to invest in entities that are themselves subject to leverage, which may be substantial, including private equity and real estate vehicles. Debt may be placed on investments, including real estate and private loans, at the time of purchase, or subsequent to purchase. In limited circumstances, the Baupost Partnerships may provide additional security or a guarantee in connection with the issuance of such debt, or in connection with other types of obligations of portfolio investments. Baupost may also cause the Baupost Partnerships to guarantee or backstop certain obligations of third parties such as Baupost's operating partners in connection with underlying transactions. In connection with purchase obligations or other commitments, a Partnership may incur financial obligations on a joint basis with other Baupost Partnerships, other affiliated entities (e.g., special-purpose vehicles), or third parties, including but not limited to guarantees or other obligations undertaken by Baupost on behalf of the funds it manages, and such financial obligations may exceed such Partnership's pro rata share of its interest in the applicable investment. However, a Partnership will not incur a financial obligation on a joint basis with another of the Baupost Partnerships, other affiliated entities, or third parties unless Baupost believes that such Partnership and the other of the Baupost Partnerships, other affiliated entities, or third parties that are parties to the joint obligation will each be able to bear its pro rata share of the relevant obligation. In connection with the foregoing, a Partnership may enter into contribution agreements in order that such Partnership will not bear more than its pro rata share of any such joint obligation.

Terrorism and Catastrophe Risks

The Baupost Partnerships may be subject to the risk of loss arising from exposure that they may incur, indirectly, due to the occurrence of various events, including, without limitation, hurricanes, earthquakes and other natural disasters, terrorism, pandemics or other health emergencies and other catastrophic events.

Coronavirus Risks

In December 2019, the virus SARS-CoV-2, which causes the coronavirus disease known as COVID-19, surfaced in Wuhan, China. The disease spread around the world, resulting in the temporary closure of many corporate offices, retail stores, and manufacturing facilities across the globe, as well as the implementation of travel restrictions and remote working and "shelter-in-place" or similar policies by numerous companies and national and local governments. These actions caused the disruption of manufacturing supply chains and consumer demand in certain economic sectors, resulting in significant disruptions in local and global economies. Such disruptions continue to be felt, as many countries and U.S. states struggle to contain the virus and its variants. The short-term and long-term impact of COVID-19 on the operations of Baupost and the performance of the Baupost Partnerships is difficult to predict. Any potential impact on such operations and performance will depend to a large extent on future developments and actions taken by authorities and other entities to contain COVID-19 and its economic impact. These potential impacts, while uncertain, could adversely affect the performance of the Baupost Partnerships.

Defined Benefit Plan Risks

Under the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code, all members of a group of commonly controlled trades or businesses are jointly and severally liable for certain of each other's obligations to any defined benefit pension plans maintained by an entity in the controlled group or to which such entity is obligated to contribute. These obligations may include the obligation to make required pension contributions, the obligation to fund any deficit amount upon pension plan termination and the obligation to pay withdrawal liability owed to a multiemployer plan to which such entity makes contributions. Accordingly, if, as a result of an investment, the Baupost Partnerships are in the same control group with an entity subject to such obligations, the Baupost Partnerships could be held liable for certain of the defined benefit pension obligations of such entity. While Baupost seeks to avoid this risk in the way it structures the investments made by the Baupost Partnerships, it may not always be successful.

**Investment Risks Associated with Specific Investment Types**

Equity Securities Generally

The value of equity securities of public and private, listed and unlisted companies and equity derivatives generally varies with the performance of the issuer and movements in the equity

markets. As a result, the Baupost Partnerships may suffer losses if they invest in equity instruments of issuers whose performance diverges from Baupost's expectations or if equity markets generally move in a single direction and the Baupost Partnerships have not hedged against such a general move. The Baupost Partnerships also may be exposed to risks that issuers will not fulfill contractual obligations such as, in the case of convertible securities or private placements, delivering marketable common stock upon conversions of convertible securities and registering restricted securities for public resale.

Preferred Stock

Investments in preferred stock involve risks related to priority in the event of bankruptcy, insolvency or liquidation of the issuing company and risks related to how dividends are declared. Preferred stock ranks junior to debt securities in an issuer's capital structure and, accordingly, is subordinate to all debt in bankruptcy. Preferred stock generally has a preference as to dividends. Such dividends are generally paid in cash (or additional shares of preferred stock) at a defined rate, but unlike interest payments on debt securities, preferred stock dividends are payable only if declared by the issuer's board of directors. Preferred stock may also be subject to optional or mandatory redemption.

Convertible Securities

A convertible security may be subject to redemption at the option of the issuer at a price established in the convertible security's governing instrument. If a convertible security held by the Baupost Partnerships is called for redemption, the Baupost Partnerships will be required to permit the issuer to redeem the security, convert it into the underlying common stock or sell it to a third party. Any of these actions could have an adverse effect on a Partnership's ability to achieve its investment objective.

Debt Securities

Fixed-income securities are subject to market and credit risk. Market risk relates to changes in a security's value as a result of changes in interest rates generally. Credit risk relates to the ability of the issuer to make payments of principal and interest.

Debt securities in which the Baupost Partnerships invest may or may not be rated by rating agencies such as Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's Ratings Services ("S&P"), and, if rated, such rating may range from the very highest to the very lowest, currently C for Moody's and D for S&P. Securities rated below investment grade (below Baa3 if rated by Moody's and below BBB- if rated by S&P) normally provide a yield or yield to maturity that is significantly higher than that of investment-grade issues, but are predominately speculative with respect to capacity to pay interest and repay principal. The lower-rated categories include debt securities that are in default and debt securities of issuers that are insolvent. The rating

assigned to a security by Moody's or S&P does not reflect an assessment of the volatility of the security's market value or the liquidity of an investment in the security.

The values of lower-rated securities (including unrated securities of comparable quality) generally fluctuate more than those of higher-rated securities, although they may be less sensitive to interest rate changes. In addition, the lower rating reflects a greater possibility that the financial condition of the issuer, adverse changes in general economic conditions or an unanticipated rise in interest rates may impair the ability of the issuer to make payments of principal and income. The inability (or perceived inability) of issuers to make timely payment of interest and principal would likely make the values of fixed-income securities held by the Baupost Partnerships more volatile and could limit the Baupost Partnerships' ability to sell their securities at prices approximating the values Baupost had placed on such securities. In addition, the market price of lower-rated securities is likely to be more volatile because: (i) an economic downturn or increased interest rates may have a more significant effect on the yield, price and potential for default; (ii) the market may at times become less liquid or respond to adverse publicity or investor perceptions, increasing the difficulty in disposing of the securities; and (iii) past legislation has limited (and future legislation may further limit) investment by certain institutions in lower-rated securities or the tax deductibility of the interest by the issuer, and such factors may adversely affect the value of such securities. The Baupost Partnerships will not necessarily dispose of a security when its rating is reduced below its rating at the time of purchase and may buy more.

Certain securities held by the Baupost Partnerships may permit the issuer of such securities at its option to "call," or redeem, its securities. If an issuer were to redeem securities held by the Baupost Partnerships during a time of declining interest rates, the Baupost Partnerships may not be able to reinvest the proceeds in securities providing the same investment return as the securities redeemed.

The Baupost Partnerships may at times invest in so-called "zero-coupon" bonds and "payment-in-kind" bonds. Zero-coupon bonds do not pay interest currently for their entire lives and normally are issued at a significant discount from their principal amount in lieu of paying interest periodically. Payment-in-kind bonds allow the issuer, at its option, to make current interest payments on the bonds either in cash or in additional bonds. Such investments may experience greater fluctuation in market value in response to changes in market interest rates than bonds that pay interest currently in cash. Both zero coupon and payment-in-kind bonds allow an issuer to avoid the need to generate cash to meet current interest payments, but also may require a higher rate of return to attract investors who are willing to defer receipt of such cash. Accordingly, such bonds may involve greater credit risks than bonds paying interest currently.

Certain debt instruments held by the Baupost Partnerships may be non-performing or in default. Furthermore, the obligor or relevant guarantor may also be in bankruptcy or liquidation. There can be no assurance as to the amount and timing of payments, if any, with respect to such debt instruments.

The Baupost Partnerships may invest in liquid bonds that later become illiquid (e.g., the issuer of a bond held by the Baupost Partnerships enters into bankruptcy proceedings causing interest payments on the bond to be deferred or the maturity date of the bond to be deferred indefinitely).

Distressed Investments

The Baupost Partnerships have invested and expect to invest in the securities and obligations of distressed and bankrupt issuers, including debt obligations that are in covenant or payment default. Such investments generally are considered speculative. The repayment of defaulted obligations is subject to significant uncertainties. Defaulted obligations might be repaid, if at all, only after lengthy workout or bankruptcy proceedings, during which the issuer might not make any interest or other payments and the amount of any recovery may be affected by the relative security of the Baupost Partnerships' investments in the capital structure of the issuer. In certain periods, there may be little or no liquidity in the markets for these securities or instruments. In addition, the prices of such securities or instruments may be subject to periods of abrupt and erratic market movements and above-average price volatility. It may be more difficult to value such securities and the spread between the bid and asked prices of such securities may be greater than normally expected. If Baupost's evaluation of the risks and anticipated outcome of an investment in a distressed security should prove incorrect, the Baupost Partnerships may lose a substantial portion or all of their investment or they may be required to accept cash and/or securities with a value less than the Baupost Partnerships' original investments. In addition, distressed investments may also be adversely affected by laws relating to, among other things, fraudulent transfers and other voidable transfers or payments, lender liability and the bankruptcy court's power to disallow, reduce, subordinate, recharacterize debt as equity or disenfranchise particular claims. Payments and distributions may be disgorged if any such payment or distribution is later determined to have been a fraudulent conveyance or a preferential payment. The EU Bank Recovery and Resolution Directive (2014/59/EU) equips national authorities in member states of the European Union with tools and powers for preparatory and preventive measures, including, in the case of derivatives transactions, powers to close-out such transactions or suspend any rights to close-out such transactions if a relevant institution is deemed likely to fail.

Merger Arbitrage and Reorganization Transactions

The Baupost Partnerships have invested and expect to invest in the securities of companies involved in mergers, consolidations, liquidations and reorganizations or as to which there exist tender or exchange offers, including, without limitation, negotiated, or "friendly," reorganizations and non-negotiated, or "hostile," takeover attempts (collectively, "Reorganization Transactions").

The Baupost Partnerships invest in certain Reorganization Transactions as part of a merger arbitrage strategy. The success of a merger arbitrage investment depends upon Baupost's ability to identify and exploit merger activity to capture the spread between current market values of securities and their values after successful completion of a merger, restructuring or similar

corporate transaction. Merger arbitrage investments may incur significant losses if anticipated merger or acquisition transactions are not consummated. The consummation of mergers, tender offers and exchange offers can be prevented or delayed by a variety of factors, including: (i) regulatory and antitrust restrictions; (ii) political factors; (iii) industry weakness; (iv) stock-specific events; and (v) failed financings.

The Baupost Partnerships will not invest their assets in a Reorganization Transaction unless Baupost determines that the probability of a timely and successful completion of the transaction outweighs any risks associated with possible delays in its successful completion. There can be no assurance that any Reorganization Transaction proposed at the time the Baupost Partnerships make investments will be consummated or will be consummated on the terms and within the time period contemplated.

Illiquid Investments

The Baupost Partnerships have purchased and expect to purchase illiquid investments, which include securities whose disposition is restricted by the securities laws, by agreement or by other characteristics inherent in the investment or in the markets or other mechanisms by which such investment trades. For example, Baupost frequently invests in investment vehicles whose principal assets are comprised of real estate. These investments are typically highly illiquid.

The Baupost Partnerships may not be able to dispose of illiquid investments readily or may be contractually prohibited from disposing of such securities for a period of time. Accordingly, if the Baupost Partnerships' portfolios become more heavily weighted towards illiquid investments, the Baupost Partnerships' ability to redeem limited partnership interests in cash will be limited.

Securities that have not been registered under the Securities Act of 1933, as amended, are referred to as private placements or restricted securities and are purchased directly from the issuer or in the secondary market. Limitations on resale may have an adverse effect on the marketability of such securities. The Baupost Partnerships may have to register such restricted securities in order to dispose of them, resulting in additional expense and delay. For example, the Baupost Partnerships may purchase securities in PIPE transactions. Until the public registration process is completed, the securities acquired in PIPE transactions are restricted as to resale and the Baupost Partnerships cannot freely trade the securities. See "PIPE Transactions." There is no assurance that any restricted securities will be publicly registered, or that the registration will remain in effect. Trading volume also may be limited even for registered securities.

In addition, the Baupost Partnerships have invested and expect to invest in private equity investments. Such securities are illiquid and difficult to price for a variety of reasons. Because those securities are not regularly traded, even among institutional investors, a reliable arms-length price often is not available as a pricing benchmark. Furthermore, the value of illiquid investments

in private companies may depend heavily on the complex legal rights attached to the securities themselves that are difficult to evaluate.

The Baupost Partnerships may invest in liquid securities that later become illiquid, for example, if Baupost or an affiliate serves on a creditor's or other committee in a bankruptcy proceeding or due to trade or other restrictions on certain securities. Such restriction may be of an uncertain or protracted duration.

Baupost determines, in its sole discretion, whether and when a particular illiquid investment, or portion thereof, should be designated as a restricted investment and whether and when a restricted investment, or portion thereof, should no longer be designated as such. The Baupost Partnerships regularly hold investments that have significant characteristics of illiquidity and are not designated as restricted investments.

Restricted investments pursuant to certain of the LP Agreements can be designated as such up to certain thresholds set forth in those LP Agreements, with exceptions for follow-on investments, hedges and previously-made commitments, each of which can continue to be designated as restricted investments after the threshold is reached. When calculating the thresholds, certain non-discretionary commitments of the Baupost Partnerships associated with restricted investments are deemed fully funded. For this purpose, direct obligations of the Baupost Partnerships are generally counted toward the thresholds based on the full value of the obligations, whereas guarantees, backstops and contingent obligations, such as guarantees of third-party obligations, are estimated by Baupost using its judgment, taking into account factors such as the likelihood of funding and expected amount of funding. Certain direct obligations are also estimated by Baupost in its judgment when Baupost believes that the full value of the obligation differs from the amount that is likely to be funded. A funding obligation could be greater than Baupost's estimate.

Bank Loans

The Baupost Partnerships have invested and expect to invest in bank loans. Risks associated with bank loans include (i) the fact that prepayments may occur at any time without premium or penalty and that the exercise of prepayment rights during periods of declining spreads could cause the Baupost Partnerships to reinvest prepayment proceeds in lower-yielding investments; (ii) the borrower's inability to meet principal and interest payments on its obligations (i.e., credit risk); and (iii) price volatility due to such factors as interest rate sensitivity, market perception of the creditworthiness of the borrower and general market liquidity (i.e., market risk). If bank loans become nonperforming, the loans may require substantial workout negotiations or restructuring that may result in, among other things, a substantial reduction in the interest rate and/or a substantial write-down of the principal of the loan. In addition to the risks noted above, due to required third-party consents or other reasons, certain loans may not be purchased or sold as easily or as quickly as publicly-traded securities. Moreover, historically, the trading volume in the loan market has not been as liquid as the market for public securities.

The Baupost Partnerships may acquire interests in loans either directly (by way of assignment ("Assignment")) or indirectly (by way of participation ("Participation")) or through the acquisition of synthetic securities, structured finance securities or interests in lease agreements that have the general characteristics of loans and are treated as loans for withholding tax purposes. The Baupost Partnerships may also originate loans. The purchaser, in an Assignment of a loan obligation, typically succeeds to all the rights and obligations of the selling institution (the "Selling Institution") and becomes a lender under the loan or credit agreement with respect to the debt obligation. In contrast, Participations acquired by the Baupost Partnerships in a portion of a debt obligation held by a Selling Institution typically result in a contractual relationship only with such Selling Institution, not with the obligor. The Baupost Partnerships would have the right to receive payments of principal, interest and any fees to which they are entitled under the Participation only from the Selling Institution and only upon receipt by the Selling Institution of such payments from the obligor. In purchasing a Participation, the Baupost Partnerships generally will have no right to enforce compliance by the obligor with respect to the terms of the loan or credit agreement or other instrument evidencing such debt obligation, nor any rights of setoff against the obligor, and the Baupost Partnerships may not directly benefit from the collateral supporting the debt obligation in which they have purchased the Participation. As a result, the Baupost Partnerships would assume the credit risk of both the obligor and the Selling Institution. In the event of the insolvency of the Selling Institution, the Baupost Partnerships may be treated as general creditors of the Selling Institution in respect of the Participation and may not benefit from any setoff between the Selling Institution and the obligor.

Purchasers of loans are predominately commercial banks, investment funds and investment banks. As secondary market trading volumes increase, new loans frequently contain standardized documentation to facilitate loan trading that may improve market liquidity. There can be no assurance, however, that future levels of supply and demand in loan trading will provide an adequate degree of liquidity or that the current level of liquidity will continue. Because holders of such loans may be provided confidential information relating to the borrower, the unique and customized nature of the loan agreement and the private syndication of the loan, such loans are not purchased or sold as easily as publicly-traded securities are purchased or sold. In addition, historically the trading volume in the loan market has been small relative to the market for high-yield debt securities.

Loan Origination

The Baupost Partnerships have engaged and expect to engage in loan origination activities. Such activities may subject the Baupost Partnerships or Baupost to regulatory requirements under the laws of certain jurisdictions. If the Baupost Partnerships originate loans with the intention of issuing participations to others with respect to the Baupost Partnerships' exposure to such loans, and if the Baupost Partnerships are unable to successfully close transactions for such

participations, the Baupost Partnerships will be forced to hold their excess interest in such loans for an indeterminate period of time.

Trade Claims

The Baupost Partnerships have purchased and expect to purchase claims against companies, including insolvent companies. These claims are typically unsecured and generally represent money due to a creditor or a supplier of goods or services to such company. An investment in trade claims is speculative and carries a high degree of risk. Trade claims are illiquid instruments that generally do not pay interest and there can be no guarantee that the debtor will ever be able to satisfy the obligation on the trade claim. Such claims are typically unsecured and may be subordinated to other unsecured obligations of a debtor, and generally are subject to defenses of the debtor with respect to the underlying transaction giving rise to the trade claim. Although Baupost endeavors to protect against such risks in connection with the evaluation and purchase of claims, trade claims are subject to risks not generally associated with standardized securities and instruments due to the idiosyncratic nature of the claims purchased. These risks include the risk that the debtor may contest the allowance of the claim due to disputes the debtor has with the original claimant or the inequitable conduct of the original claimant, or due to administrative errors in connection with the transfer of the claim. Recovery on allowed trade claims also may be impaired if the anticipated dividend payable on unsecured claims in the bankruptcy is not realized or if the timing of the bankruptcy distribution is delayed. Accordingly, if the Baupost Partnerships receive payment in respect of the trade claim investment, the payment may be in an amount less than what the Baupost Partnerships paid for or otherwise expected to receive in respect of the claim.

Additionally, there can be restrictions on the purchase, sale and/or transferability of trade claims during all or part of a bankruptcy proceeding. The markets in trade claims generally are not regulated by U.S. federal securities laws or the SEC. The purchase and sale of trade claims are generally consummated by written contract between the parties and contain customary language regarding the return of a portion of the purchase price in the event that all or a portion of the claim is disallowed or rejected. Because trade claims are unsecured, holders of trade claims may have a lower priority in terms of payment than certain other creditors in a bankruptcy proceeding.

Because they are not negotiable instruments, trade claims are typically less liquid than negotiable instruments. Given these factors, trade claims often trade at a discount to other *pari passu* instruments.

Investments Related to Legal Proceedings and Judgments

The Baupost Partnerships have invested and expect to invest in interests in, or related to, legal proceedings or judgments including, but not limited to, the purchase of rights to bring or pursue litigation or arbitration claims, the making of, or investing, in loans to parties to litigation or

arbitration proceedings or in potential future recoveries in respect thereof (generally referred to as "litigation funding"), and debt or equity investments in companies engaged in litigation or arbitration proceedings. In addition to other risks commonly associated with loans, debt and equity investments, such investments (referred to collectively herein as "litigation investments") are subject to a number of significant risks, including, but not limited to, those described herein.

The Baupost Partnerships' ability to achieve their investment objectives with respect to litigation investments depends on whether claims in which the Baupost Partnerships invest are successful. Assessing the values, strengths and weaknesses of a claim is complex, and the outcome is not certain.

While Baupost seeks to align incentives between the Baupost Partnerships, the claimant and the law firm representing the claimant for each litigation investment, it may not always be successful, which could negatively impact the investment.

Baupost carefully considers the laws, regulations and ethical rules that apply to each litigation investment, including their impact on the assignment of claims and/or the participation in a lawyer's contingent fee interests, which vary by jurisdiction and are complex. While Baupost seeks to structure litigation investments to comply with all applicable laws, regulations and ethical rules, changes to these could reduce the value of the Baupost Partnerships' pre-existing litigation investments in such jurisdictions. Furthermore, the Baupost Partnerships' failure to comply with any applicable laws, regulations or ethical rules relating to a litigation investment, whether actual or alleged, could expose Baupost Partnerships to potential liabilities, which could adversely affect the Baupost Partnerships.

If the defendant in a case is unable to pay, or seeks to challenge the validity of, a judgment or award, the Baupost Partnerships may encounter difficulties obtaining recoveries. In addition, certain aspects of litigation recoveries, including the timing and amounts recovered, are outside of the control of the Baupost Partnerships and Baupost. It is also possible that one or more of the parties to a litigation (whether a private party or a sovereign government) may threaten regulatory action or litigation and/or institute regulatory actions or lawsuits against the Baupost Partnerships and/or Baupost (and/or its employees) in an attempt to undermine an investment or prospective investment, and an unfavorable outcome from any such action or litigation could reduce the profitability of the Baupost Partnerships and may ultimately cause losses.

<u>Sovereign Debt</u>

The Baupost Partnerships have invested and expect to invest in sovereign debt. Investment in sovereign debt can involve a high degree of risk. The governmental entity that controls the repayment of sovereign debt may not be able or willing to repay the principal and/or interest when due in accordance with the terms of the debt. A governmental entity's willingness or ability to repay principal and interest when due may be affected by, among other factors, its cash flow

situation, the extent of its non-U.S. reserves, the availability of sufficient foreign exchange on the date a payment is due, the relative size of the debt service burden to the economy as a whole, the governmental entity's policy toward the International Monetary Fund, the political constraints to which a governmental entity may be subject and changes in governments and political systems. At certain times, certain countries (particularly emerging market countries) have declared moratoria on the payment of principal and interest on external debt. Governmental entities may also depend on expected disbursements from non-U.S. governments, multilateral agencies and others to reduce principal and interest arrearages on their debt. The commitment on the part of these governments, agencies and others to make such disbursements may be conditioned on a governmental entity's implementation of economic reforms and/or economic performance and the timely service of such debtor's obligations. Failure to implement such reforms, achieve such levels of economic performance or repay principal or interest when due may result in the cancellation of such third parties' commitments to lend funds to the governmental entity, which may further impair such debtor's ability or willingness to service its debts in a timely manner. Consequently, governmental entities may default on their sovereign debt. Holders of sovereign debt may be requested to participate in the rescheduling of such debt and to extend further loans to governmental entities. There is no bankruptcy proceeding by which sovereign debt on which governmental entities have defaulted may be collected in whole or in part.

Non-U.S. Securities and Emerging Markets Securities

The Baupost Partnerships have invested and expect to invest in securities principally or exclusively traded in non-U.S. markets. Since non-U.S. securities are normally denominated and traded in non-U.S. currencies, the value of the Baupost Partnerships' assets may be affected favorably or unfavorably by currency exchange rates and exchange control regulations (which may include suspension of the ability to transfer currency from a given country and repatriation of investments). Exchange rates with respect to certain currencies may be particularly volatile. There may be less information publicly available about a non-U.S. company than about a U.S. company, and non-U.S. companies are not generally subject to accounting, auditing and financial reporting standards and practices comparable to those in the United States. The securities of some non-U.S. companies are less liquid and at times more volatile than securities of comparable U.S. companies. Non-U.S. brokerage commissions and other fees are also sometimes higher than in the United States. Non-U.S. settlement procedures and trade regulations may involve certain risks (such as delay in payment or delivery of securities or in the recovery of the Baupost Partnerships' assets held abroad) and expenses not present in the settlement of domestic investments. Baupost generally retains, but in certain circumstances may delegate to executing brokers or custodians, the discretion to select currency exchange rates and execution times in connection with non-U.S. currency exchange transactions.

Some countries in which the Baupost Partnerships may invest may have fixed or managed currencies that are not free-floating against the U.S. dollar. Further, certain currencies may not be

traded internationally. Certain of these currencies have experienced or may experience a steady devaluation relative to the U.S. dollar. Any devaluations in the currencies in which the Baupost Partnerships' portfolio securities are denominated may have a detrimental impact on the Baupost Partnerships. Many countries in which the Baupost Partnerships may invest have experienced substantial, and in some periods extremely high, rates of inflation for many years. Inflation and rapid fluctuations in inflation rates have had and may continue to have negative effects on the economies and securities markets of certain countries.

In addition, there may be a possibility of nationalization or expropriation of assets, imposition of currency exchange controls, confiscatory taxation, political or financial instability and diplomatic developments that could affect the value of the Baupost Partnerships' investments in certain non-U.S. countries. Legal remedies available to investors in certain non-U.S. countries may be more limited than those available with respect to investments in the United States or in other non-U.S. countries. The laws of some non-U.S. countries may limit the Baupost Partnerships' ability to invest in securities of certain issuers located in those non-U.S. countries.

The risks described above, including the risks of nationalization or expropriation of assets, are typically greater if the Baupost Partnerships invest in issuers located in under-developed and developing nations, which are sometimes referred to as "emerging markets." Investments in securities of issuers located in countries with emerging economies or securities markets are speculative and subject to certain special risks. Political and economic structures in many of these countries may be in their infancy and developing rapidly, and such countries may lack the social, political and economic stability of more developed countries. Certain of these countries have in the past failed to recognize private property rights and have at times nationalized or expropriated the assets of private companies. In some instances it may be necessary for the Baupost Partnerships to appoint a local agent for the purpose of effecting the registration or sale of securities. There can be no assurance that the attorneys-in-fact that the Baupost Partnerships may from time to time appoint to serve as agents will properly effect such transactions or that they will not attempt to exceed their authority.

Emerging markets are also subject to unanticipated political or social developments that may affect the values of the Baupost Partnerships' investments in these countries and the availability to the Baupost Partnerships of additional investments in these countries. The small size, limited trading volume and relative nascency of the securities markets in these countries may make the Baupost Partnerships' investments in such countries illiquid and more volatile than investments in more developed countries. There may be little financial or accounting information available with respect to issuers located in these countries, and it may be difficult, as a result, to assess the value or prospects of an investment in such issuers.

Currencies

The Baupost Partnerships have traded and expect to trade currencies. A principal risk in trading currencies is the rapid fluctuation in the market prices of currency contracts. Prices of currency contracts traded by the Baupost Partnerships are affected generally by relative interest rates, which in turn are influenced by a wide variety of complex and difficult to predict factors such as money supply and demand, balance of payments, inflation levels, fiscal policy, and political and economic events. In addition, governments from time to time intervene, directly and by regulation, in these markets, with the specific effect or intention of influencing prices that may, together with other factors, cause all of such markets to move rapidly in the same direction because of, among other things, interest rate fluctuations.

Initial Public Offerings

Investments in initial public offerings (or shortly thereafter) may involve greater risks than investments in secondary public offerings or purchases on a secondary market due to a variety of factors, including, without limitation, the limited number of shares available for trading, unseasoned trading, lack of investor knowledge of the issuer and limited operating history of the issuer. In addition, some companies that make initial public offerings are involved in relatively new industries or lines of business, which may not be widely understood by investors. Some of these companies may be undercapitalized or regarded as developmental stage companies, without revenues or operating income, or the near-term prospects of achieving them. These factors may contribute to substantial price volatility for such securities and, thus, may impact the value of the Baupost Partnerships' interests.

The Baupost Partnerships have in the past and expect to purchase equity securities in an initial public offering. Such offerings are considered "new issues," as defined in Rule 5130 of the Financial Industry Regulatory Authority, Inc. ("FINRA"). Rule 5130 generally prohibits members of FINRA from selling new issues to an account in which a "restricted person" (as defined in Rule 5130) has an interest, unless the fund has a mechanism in place that limits such "restricted person" from receiving allocations of profits and losses from new issues in excess of certain thresholds. Furthermore, FINRA Rule 5131 generally prohibits members of FINRA from selling new issues to an account in which directors and executive officers of certain public and non-public companies (or persons receiving material support therefrom) have an interest, unless the fund has a mechanism in place that limits such persons restricted by Rule 5131 from receiving allocations of profits and losses from new issues in excess of certain thresholds. To allow the Baupost Partnerships to participate in new issues, Baupost has developed and implemented procedures to treat separately the interests in the Baupost Partnerships of "restricted persons" and persons covered by FINRA Rule 5130, on the one hand, and persons not so restricted or covered, on the other, relying on the representations investors make in a subscription agreement or periodic questionnaires distributed by Baupost to make such determinations. If an investor is unable or unwilling to complete the applicable information in a subscription agreement or periodic

questionnaires, Baupost may treat such investor as a restricted person and that investor may be limited in its ability to participate on a pro rata basis with investors who are not restricted persons in any profits or losses attributable to such Partnership's investment, if any, in new issues.

Securities of Small-to-Medium Sized Companies

The Baupost Partnerships have invested and expect to invest in securities of small-to-medium sized companies. Such companies may have limited product lines, markets or financial resources, and may be dependent on a limited management group. The risk of bankruptcy or insolvency of many smaller companies (and the corresponding losses to investors) may be higher than for larger, "blue-chip" companies. Securities of small-to-medium sized companies may be traded in the over-the-counter ("OTC") markets. While OTC markets have grown rapidly, many OTC securities trade less frequently and in smaller volumes than exchange-listed securities. The values of these securities may fluctuate more sharply than exchange-listed securities, and the Baupost Partnerships may experience difficulty in acquiring or disposing of positions in these securities at prevailing market prices.

Special Purpose Acquisition Companies

The Baupost Partnerships have invested and expect to invest in units, shares, warrants, and other interests in special purpose acquisition companies or similar entities that pool funds to seek potential acquisition opportunities (collectively, "SPACs"). The funds raised by a SPAC in its initial public offering ("IPO") are held in trust until the SPAC successfully consummates an initial business combination ("IBC") or until redeemed by public shareholders in connection with an IBC, and the SPAC promoter typically receives a discounted stake in the SPAC. If the SPAC fails to consummate an IBC within a specified timeframe, typically 24 months (which may be extended in certain circumstances), the trust proceeds are returned to the public shareholders.

The Baupost Partnerships may also invest in a SPAC through a private placement in connection with an IBC. For these investments, the Baupost Partnerships may agree not to transact in or hedge the securities of the SPAC for a specified period of time. As a result, the Baupost Partnerships could have a prolonged period of exposure to a particular SPAC without the ability to liquidate or hedge the position. Such investments are also subject to the risks associated with PIPEs as discussed in "PIPE Transactions."

An investment in a SPAC is subject to a variety of risks, including, among others, that (i) as a newly formed company with no operating history, there is little basis on which to evaluate the SPAC's ability to consummate a successful IBC other than the track record of the its management team; (ii) the SPAC may encounter substantial completion for attractive targets, particularly given the substantial increase in SPACs in recent years; (iii) the SPAC may not identify an attractive business combination target, and the SPAC may be required to liquidate and return any remaining monies to shareholders; (iv) a business combination, if effected, may prove unsuccessful and an

investment in the SPAC may lose value; (v) the warrants or other rights with respect to the SPAC held by the Baupost Partnerships may expire worthless or may be repurchased or retired by the SPAC at an unfavorable price; (vi) the Baupost Partnerships may be delayed in receiving any redemption or liquidation proceeds from a SPAC to which it is entitled; and (vii) an investment in a SPAC may be diluted in connection with the business combination or by additional financings.

PIPE Transactions

Private investments in public companies whose stocks are quoted on stock exchanges or trade in the over-the-counter securities market (a type of investment commonly referred to as a "PIPE" transaction) will generally result in the Baupost Partnerships acquiring either restricted stock or an instrument convertible into restricted stock. As with investments in other types of restricted securities, such an investment may be illiquid. The Baupost Partnerships' ability to dispose of securities acquired in PIPE transactions may depend on the registration of such securities for resale. A number of factors may prevent or delay a proposed registration. Alternatively, it may be possible for securities acquired in a PIPE transaction to be resold in transactions exempt from registration in accordance with Rule 144 under the Securities Act of 1933, or otherwise under the U.S. federal securities laws. There is no guarantee that there will be an active or liquid market for the stock of any small capitalization company due to the possible small number of stockholders. As a result, even if the Baupost Partnerships are able to have securities acquired in a PIPE transaction registered or sell such securities through an exempt transaction, the Baupost Partnerships may not be able to sell all the securities on short notice, and the sale of the securities could lower the market price of the securities. There is no guarantee that an active trading market for the securities will exist at the time of disposition of the securities, and the lack of such a market could hurt the market value of the investments of the Baupost Partnerships.

Short Sales

While not core to the investment strategy, the Baupost Partnerships from time to time engage in short sales (and also gain short exposure through the use of derivatives, including forward sales, futures and swaps). In a short sale, the seller sells a security that it does not own, typically a security borrowed from a broker or dealer. Because the seller remains liable to return the underlying security that it borrowed from the broker or dealer, the seller must purchase or otherwise acquire the security prior to the date on which delivery to the broker or dealer is to be made. The Baupost Partnerships will typically engage in short sales when Baupost believes the value of the security will decline or as part of a hedging strategy or part of a stub trade. Short sales exposes the Baupost Partnerships to the risk of liability for the market value of the security sold. If the price of the security sold short increases between the time of the short sale and the time the Baupost Partnerships replace the borrowed security, the Baupost Partnerships will incur a loss; conversely, if the price declines, the Baupost Partnerships will realize a gain. Any gain will be reduced, and any loss increased, by the transaction costs associated with short sales. Although the Baupost Partnerships' gains are limited to the price at which they sold the security short, their

potential loss is unlimited if the Baupost Partnerships do not own the security. In addition, there can be no assurance that securities necessary to cover a short position will be available for purchase or that securities will be available to be borrowed by the Baupost Partnerships at a reasonable cost. If a request for return of borrowed securities occurs at a time when other short sellers of the security are receiving similar requests, a "short squeeze" can occur, and the Baupost Partnerships may be compelled to replace borrowed securities previously sold short with purchases on the open market at the most disadvantageous time, possibly at prices significantly in excess of the proceeds received in originally selling the securities short.

The SEC has in the past adopted interim rules requiring reporting of all short positions above a certain de minimis threshold and may in the future adopt rules requiring monthly public disclosure of short positions. In addition, other non-U.S. jurisdictions where the Baupost Partnerships may trade have adopted reporting requirements.

Repurchase Agreements

The Baupost Partnerships have entered and may enter into repurchase agreements with banks and broker-dealers; in such agreements the Baupost Partnerships acquire a security for cash and obtain a simultaneous commitment from the seller to repurchase the security at an agreed-upon price and date. The resale price is in excess of the acquisition price and reflects an agreed upon market rate unrelated to the coupon rate of the purchased security. Baupost will generally monitor such transactions to try to ensure that the value of the underlying securities will be at least equal at all times to the total amount of the repurchase obligation, including the interest factor. Such transactions afford an opportunity for the Baupost Partnerships to earn a return on temporarily available cash at no market risk, although there is a risk that the seller may default in its obligation to pay the agreed upon sum on the redelivery date. Such a default may subject the Baupost Partnerships to expenses, delays and risks of loss. In addition, if the seller should be involved in bankruptcy or insolvency proceedings, the Baupost Partnerships may incur delays and costs in selling the underlying security or may suffer a loss of principal and interest if the Baupost Partnerships are treated as unsecured creditors and are required to return the underlying collateral to the seller's estate. The Baupost Partnerships may also enter into reverse repurchase agreements that involve the risk that the market value of the securities retained by the Baupost Partnerships may decline below the price of the securities the Baupost Partnerships have sold but are obligated to repurchase under the agreement. In the event the buyer of securities under a reverse repurchase agreement files for bankruptcy or becomes insolvent, the Baupost Partnerships' use of the proceeds of the agreement may be restricted pending a determination by the other party, or its trustee or receiver, whether to enforce the Baupost Partnerships' obligations to repurchase the securities.

Mortgage-Backed and Asset-Backed Securities

The Baupost Partnerships have invested and expect to invest in mortgage-backed and asset-backed securities, including mortgage derivatives, frequently at discounts to original issue price because

of distress in the performance of the underlying collateral. When market interest rates decline, many mortgages are refinanced, and mortgage-backed securities are paid off earlier than expected. Prepayments may also occur on a scheduled basis or due to foreclosure. Accordingly, holders of these securities may not benefit fully from the increase in value that other fixed-income securities experience when rates decline. Furthermore, under such circumstances, the Baupost Partnerships would be forced to reinvest the proceeds of the payoff at current yields, which would be lower than those paid by the security that was prepaid. For distressed mortgage- or asset-backed securities, the continued underperformance of the collateral including rising default rates or loss severity, home price depreciation, litigation or problems with the servicing of the collateral may all contribute to increased risk of loss and price decline.

When market interest rates increase, the market values of mortgage-backed securities usually decline. At the same time, however, mortgage refinancing slows, which lengthens the effective maturities of these securities. As a result, the negative effect of the rate increase on the market value of mortgage securities is usually more pronounced than it is for other types of fixed-income securities. The ability of an issuer of asset-backed securities to enforce its security interest in the underlying assets may be limited. Government policies regarding the modification of performing or non-performing mortgages may affect the value of these securities. Asset-backed securities are subject to many of the same risks as mortgage-backed securities.

Prepayments may cause losses on securities purchased at a premium. At times, some of the mortgage-backed and asset-backed securities in which the Baupost Partnerships may invest will have higher than market interest rates and therefore will be purchased at a premium above their par value. Unscheduled prepayments, which are made at par, will cause the Baupost Partnerships to experience a loss equal to any unamortized premium. In addition, a reduction in prepayments may increase the effective maturities of these securities, subjecting them to a greater risk of decline in market value in response to rising interest rates than traditional debt securities.

Master Limited Partnerships

Investments in securities of master limited partnerships ("MLPs") involve certain risks that differ from investments in common stock, including risks related to limited control and limited rights to vote on matters affecting MLPs, risks related to potential conflicts of interest between an MLP and the MLP's general partner, including those arising from incentive distribution payments, cash flow risks, dilution risks and risks related to the general partner's right to require unit-holders to sell their common units at an undesirable time or price. Many of the Baupost Partnerships' investments in MLPs will be subject to legal and other restrictions on resale or will otherwise be less liquid than publicly-traded securities. In addition, certain tax risks are associated with investments in MLPs including without limitation, the obligation to file state tax returns and allocations from the MLP generating UBTI.

Pooled Investment Vehicles, Joint Ventures and Pass-Through Entities

The Baupost Partnerships have invested and expect to invest in other pooled investment vehicles, including real estate investment trusts, investment companies registered under the Investment Company Act, unregistered investment vehicles and other private investment vehicles managed by third parties, including operating partners engaged by Baupost to manage joint venture investments. When the Baupost Partnerships invest in joint ventures, including those with operating partners, or pooled investment vehicles, investors bear the cost of any management and performance fees of third parties in addition to the fees of the General Partners and their affiliates. Such investments may have limited liquidity, and any investment by the Baupost Partnerships in such vehicles will have the risks inherent in the instruments or other assets in which such vehicles invest.

A claim asserted against a pooled investment vehicle in which the Baupost Partnerships invest could be enforced against all of the assets of such vehicle. For example, the value of the Baupost Partnerships' investments in a pooled vehicle could be adversely affected even if the claim relates to an investment from which the Baupost Partnerships were excused from participating or if the claim relates to a particular class or sub-class of interests that the Baupost Partnerships did not hold.

Third-Party Involvement

The Baupost Partnerships have held and expect to hold a portion of their investments through partnerships, joint ventures, securitization vehicles or other entities with third-party investors. These types of investments with third-party investors involve various risks, including the risk that the Baupost Partnerships will not be able to implement investment decisions or exit strategies because of limitations on the Baupost Partnerships' control over the relevant investment entities under applicable agreements with third-party investors, the risk that a third-party investor may become bankrupt or may at any time have economic or business interests or goals that are inconsistent with those of the Baupost Partnerships, the risk that a third-party investor may be in a position to take action contrary to the Baupost Partnerships' objectives, the risk of liability based upon the actions of a third-party investor and the risk of disputes or litigation with such third-party investor and the inability to enforce fully all rights (or the incurrence of additional risk in connection with enforcement of rights) one investor may have against another, including in connection with foreclosure on investor loans because of risks arising under state law.

Operating Partners

With respect to certain real estate or private equity investments, the Baupost Partnerships have in the past entered into, and expect in the future to enter into joint ventures with third-party operating partners. Such operating partners normally manage the day-to-day operations of such investments, and perform a variety of functions such as asset management, administration, property

management, technology services, loan servicing, due diligence and idea generation. These operations are typically performed by the operating partner's personnel, not by personnel of Baupost or any of its affiliates, and Baupost does not exercise day-to-day control over or management of the operating partners. In addition, operating partners often identify potential investment opportunities to Baupost and may be compensated by the Baupost Partnerships in connection therewith. While operating partners typically co-invest in and receive a share of the profits from the assets they manage, there is a risk that their interests may not be directly aligned with those of the Baupost Partnerships, and their decisions, actions or omissions may adversely affect the Baupost Partnerships' investment in the joint venture. Since certain operating partners manage assets held by the Baupost Partnerships and assets not held by the Baupost Partnerships, operating partners may face conflicts of interest between choices that may favor one investment over another, as well as decisions regarding devotion of time and resources. The Baupost Partnerships also have provided and expect on occasion in the future to provide loans to operating partners, and such loans may be non-recourse to the borrower.

Company Ownership and Use of Special Purpose Vehicles

The Baupost Partnerships may own a controlling interest in companies in which they have invested. Because of their ownership, representation on the board of directors or other governing body and/or contractual rights, the Baupost Partnerships may be perceived as controlling, participating in the management of or influencing the conduct of such companies. This could expose the assets of the Baupost Partnerships generally to claims (for example, arising from environmental, pension or Foreign Corrupt Practices Act exposure, or arising from tax positions) by such company, its other security holders, its creditors, governmental agencies or other third parties. Such liability may not be limited to any particular asset, such as the investment giving rise to the liability, and may exceed the value of the particular investment giving rise to the liability.

In addition, Baupost has used and expects to use special-purpose entities in connection with certain transactions. Similar considerations may apply to these special-purpose entities. In addition, the bona fides of such entities may be subject to later challenge based on a number of theories, including veil piercing or substantive consolidation.

Accordingly, investors could find their limited partnership interests in the Baupost Partnerships adversely affected by a liability arising out of a particular investment (including in circumstances where a particular investor does not otherwise have exposure to the investment because it is a restricted investment).

Private Equity and Venture Capital Investments

The Baupost Partnerships have made and expect to make private equity and venture capital investments, either directly or indirectly through pooled investment vehicles or special purpose vehicles, that involve a high degree of business and financial risk. Although Baupost may acquire

control positions and/or seek protective provisions, including in certain circumstances board representation, in connection with certain of its private equity and/or venture capital investments, in other instances the Baupost Partnerships take minority positions in companies in which they invest and may do so in a purely passive role. With respect to minority private equity and/or minority venture capital investments, Baupost is typically not in a position to exercise control over the management of such companies, and, accordingly, may have a limited ability to protect the Baupost Partnerships' positions in such companies. When the Baupost Partnerships invest in private equity or venture capital through a pooled investment vehicle, investors bear the cost of any management and performance fees of third parties in addition to the fees of the General Partners and their affiliates. Such fees reduce the returns to the Baupost Partnerships.

Early-stage companies with little or no operating history, and early-stage investments generally, may require substantial additional capital to support expansion or to achieve or maintain a competitive position, may produce substantial variations in operating results from period to period or may operate at a loss. Such early-stage companies and investments may face intense competition, including competition from companies with greater financial resources, better marketing and service capabilities and a larger number of qualified management and technical personnel. Such competition, as well as other factors, may adversely affect the performance of such investments and result in substantial losses.

The Baupost Partnerships have made and may make private equity investments in highly leveraged companies. The use of such leverage may present additional risks, including that it may increase the exposure of such companies to adverse economic factors such as downturns in the economy or deterioration in the conditions of such companies or their respective industries. In the event any such company cannot generate adequate cash flow to meet debt service, the Baupost Partnerships may suffer a substantial loss of capital invested.

Investments in Regulated Industries

The Baupost Partnerships' investments may include companies in industries that are subject to significant regulation, including, but not limited to, transportation, banking and finance, media, mining, utilities and insurance. Investments in companies that are subject to greater governmental regulation pose additional risks relative to investments in other companies generally. Changes in applicable laws or regulations, or in the interpretations of these laws and regulations, could result in increased compliance costs or the need for additional capital expenditures. If the Baupost Partnerships or one of their investments fail to comply with these requirements, the Baupost Partnerships could also be subject to civil or criminal liability and the imposition of fines. The Baupost Partnerships or one of their investments could also be materially and adversely affected as a result of statutory or regulatory changes or judicial or administrative interpretations of existing laws and regulations that impose more comprehensive or stringent requirements on such an investment. Governments have considerable discretion in implementing regulations that could impact the Baupost Partnerships or their investments, and governments may be influenced by

political considerations and may make decisions that adversely affect the Baupost Partnerships or their investments.

Insurance-Related Investments

The Baupost Partnerships have in the past and may in the future make insurance-related investments. Insurance-related investments, such as investments in public and private insurance and reinsurance companies, insurance-linked securities, including private insurance, reinsurance, retrocessional reinsurance contracts, industry loss warranties, loss indemnification contracts, and insurance subrogation claims, catastrophe bonds, and other instruments linked to event-driven risks or similar factors, are subject to the risks inherent to the insurance and reinsurance industry, such as the occurrence of weather-related and other natural or man-made catastrophes. These risks are unpredictable and may result in significant losses. To the extent the Baupost Partnerships invest in insurance-related investments, a significant natural disaster, such as a hurricane or earthquake, a terrorist incident, or a series of such or similar events, could have a material, adverse effect on the Baupost Partnerships.

Real Estate-Related Transactions

The Baupost Partnerships have invested and expect to invest in real estate and in real estate-related assets. Real estate-related assets include securities that are backed by, represent interests in or are secured by real estate, as well as securities issued by companies or limited partnerships or limited liability companies that invest in real estate or interests in real estate. Investments in real estate and real estate-related assets entail certain risks due to a variety of factors, including uncertainties surrounding the underlying real estate ventures and hidden defects that might not be discovered despite reasonable due diligence. Factors affecting the performance of real estate ventures may include changes in interest rates, excess supply of real property in certain markets, satisfactory completion of construction, sufficient level of occupancy, adequacy of financing available in capital markets, competent management, rent levels and maintaining adequate rent to cover operating expenses, regulatory limits on rents, local and regional markets for competing assets, changes in applicable zoning and other laws and governmental regulations (including taxes), the ability to obtain use or development entitlements and other regulatory permits and permissions, possible environmental liabilities, natural disasters and social and economic trends.

Real estate investments that the Baupost Partnerships have made and may make include investments in and relating to non-U.S. properties. In addition to the risks associated with real estate investment generally, investment in non-U.S. properties and ventures involves additional risks such as currency exchange rate risk, liquidity risk, and the risk of different or changing property ownership and tax laws. See "Non-U.S. Securities and Emerging Markets Securities."

As noted in "Operating Partners," the Baupost Partnerships typically invest in real property through joint ventures with operating partners. In connection with these investments, the Baupost

Partnerships' joint venture will incur the burdens of ownership of real property, which include the paying of expenses and taxes, maintaining such property and any improvements thereon and ultimately disposing of such property.

With respect to investments in equity securities, debt securities or other financial instruments, including those issued by real estate investment trusts, the securities generally will be subject to the risks incident to the ownership and operation of real estate and/or risks incident to the making of nonrecourse mortgage loans secured by real estate. The Baupost Partnerships will also in large part be dependent on the ability of third parties to successfully operate the underlying real estate assets.

Many of the real estate-related assets in which the Baupost Partnerships may invest will not be readily marketable. Investments in real estate and in real estate-related assets that are not readily marketable entail additional risks, such as difficulty in pricing the real estate or other asset for purposes of determining the particular Baupost Partnership's net asset value (the "Net Asset Value") and the possibility that the Baupost Partnerships would be unable to sell the real estate or other asset at a price that Baupost believes fairly represents its intrinsic value when Baupost decides to sell it.

Potential Environmental Liability of Real Estate Investments

Under various U.S. and non-U.S. federal, state and local laws, ordinances and regulations, an owner of real property may be liable for the costs of removal or remediation of certain hazardous or toxic substances on or in such property. Such enactments often impose such liability without regard to whether the owner knew of, or was responsible for, the presence of such hazardous or toxic substances, and the liability under such enactments has in certain circumstances been interpreted to be joint and several. For example, the current owner of a parcel of land may be liable for environmental problems at, or emanating from, the parcel of land that were caused by a past owner or current operator of the site. The cost of any required remediation and the owner's liability therefore as to any property is generally not limited under such enactments and could exceed the value of the property and/or the aggregate assets of the owner. The presence of such substances, or the failure to properly remediate such substances, may adversely affect the owner's ability to sell the real estate or to borrow using such property as collateral. In addition, remediated property may attract a limited number of potential purchasers because of the property's history of contamination, which might also adversely affect the owner's ability to sell the property. Further, a transfer of property does not relieve from liability a person who owned the property at a time when hazardous or toxic substances were disposed of on, or released from, such property. In addition, noncompliance with environmental regulations may allow a governmental authority to order the owner/operator to cease operations at the property or to incur substantial costs and expenses to bring the property into compliance through the implementation of burdensome remediation or prophylactic measures. Where appropriate to reduce the possibility of liability under environmental laws, the Baupost Partnerships will seek to obtain indemnities from sellers,

purchase environmental insurance or hold title in limited liability entities. Review of environmental issues will be conducted in accordance with customary industry standards applicable to such matters. There can be no assurance that environmental laws relating to real estate transactions will not be amended in the future in ways that could adversely affect the Baupost Partnerships' investments.

Real Estate Development and Construction Risks

The Baupost Partnerships have acquired and expect to acquire equity and/or debt interests in real estate developments and/or in businesses that engage in real estate development. To the extent that the Baupost Partnerships invest in such development activities, it will be subject to the risks normally associated with such activities. Such risks include, without limitation, risks relating to the availability and timely receipt of zoning and other regulatory approvals, the cost and timely completion of construction (including risks beyond the control of the Baupost Partnerships or Baupost, such as weather or labor conditions or material shortages) and the availability of both construction and permanent financing on favorable terms. These risks could result in substantial unanticipated delays or expenses and, under certain circumstances, could prevent completion of development activities once undertaken, any of which could have an adverse effect on the financial condition and results of investments by the Baupost Partnerships.

Hedging Transactions

The Baupost Partnerships have entered and may, but are not required to, enter into hedging transactions in order to hedge risks in connection with a particular investment or transaction, with the portfolios generally or otherwise. Baupost may be unable to anticipate any particular risk and, therefore, may be unable to hedge against it. Any hedge may prove to be ineffective and may fail to hedge against the risk for which it was intended. Moreover, the Baupost Partnerships' portfolios will always be exposed to certain risks that cannot be hedged. Even if Baupost is successful in identifying appropriate hedges, such hedges may be unavailable or available only at prices deemed by Baupost to be too costly. Alternatively, Baupost may in any circumstance choose not to hedge or may choose to hedge partially. Hedging transactions may result in a poorer overall performance for the Baupost Partnerships than if the Baupost Partnerships had not engaged in such hedging transactions. Additionally, changes to the regulations applicable to the financial instruments the Baupost Partnerships use to accomplish their hedging strategy could affect the effectiveness of that strategy.

A Partnership may make two or more investments that have hedging properties with respect to one another. Because of the varying participation by investors in restricted investments and new issues, among other factors, investors may participate in these types of complementary investments in a proportion that may vary significantly from that of other investors, or may participate in only one of the underlying investments and not the other(s). As a result, such investors may not obtain Baupost's intended hedging ratio for the applicable investments.

Derivatives

The Baupost Partnerships have engaged and expect to engage in a variety of transactions using "derivatives," including options, futures and swaps. The use of derivative instruments may involve risks different from, or greater than, the risks associated with investing directly in the underlying securities, commodities or other assets (including, without limitation, differences in tax treatment). Derivatives are financial instruments the value of which depends upon, or is derived from, the value of something else, such as one or more underlying investments, indexes, interest rates or currencies. Derivatives may be traded on organized exchanges, or in individually negotiated transactions with other parties. Derivatives involve special risks and costs and may result in losses to the Baupost Partnerships. The successful use of derivatives requires sophisticated management, and will depend on the ability of Baupost to analyze and manage derivatives transactions. The prices of derivatives may move in unexpected ways, especially in abnormal market conditions. The Baupost Partnerships may use derivatives both for hedging and non-hedging purposes. These risks may be magnified in the case of complex derivatives that involve multiple underlying investments, indexes, interest rates and/or currencies.

If a derivative is used for hedging purposes, some risk may be caused by an imperfect or variable degree of correlation between movements in the price of the derivative and the price of the underlying security or instrument being hedged. In the event of an imperfect correlation between a derivative position and a portfolio position (or anticipated position) that is intended to be protected, the desired protection may not be obtained and the Baupost Partnerships may not achieve the desired hedging effect or be exposed to the risk of loss. With respect to currency hedging transactions, it is not always possible to hedge fully or perfectly against currency fluctuations affecting the value of the securities denominated in non-U.S. currencies because the value of such securities also is likely to fluctuate as a result of independent factors not related to currency fluctuations.

Some derivatives, such as swaps, have a leveraging effect and therefore may magnify or otherwise increase investment losses to the Baupost Partnerships. Other risks arise from the potential inability to terminate or sell derivatives positions. A liquid secondary market may not always exist for the Baupost Partnerships' derivatives positions at any time. In fact, many OTC instruments will not be liquid.

The Baupost Partnerships may sustain a loss as a result of the failure of the other party to a derivatives contract (a "counterparty") to comply with the terms of the contract whether due to insolvency, bankruptcy or other causes. If there is a default by a counterparty, the Baupost Partnerships will be limited to contractual remedies pursuant to the agreements related to the transaction. There is no assurance that counterparties will be able to meet their obligations pursuant to the contracts or that, in the event of default, the Baupost Partnerships will succeed in pursuing contractual remedies. The Baupost Partnerships will generally attempt to mitigate such risk by requiring counterparties to post additional collateral as the value of a swap with such

counterparty increases, but the collateral may be insufficient to cover the counterparty's obligations or the counterparty may refuse to post additional collateral. If a counterparty's creditworthiness declines, the value of a derivative with such counterparty may also decline.

The Baupost Partnerships will also be subject to counterparty risk in certain situations where the Baupost Partnerships are required to collateralize their position. For example, certain swaps and other transactions will require the Baupost Partnerships to post margin with a counterparty. These situations involve some risk to the Baupost Partnerships if the counterparty defaults on its obligations (or becomes insolvent or is otherwise unable to perform) and the Baupost Partnerships are delayed in or prevented from recovering the collateral. In such cases, the value of the posted collateral may be less than the value of such posted securities or assets would otherwise have been if they were not encumbered. In addition, the Baupost Partnerships may be required to post collateral to cover any delay between the date of a trade and the settlement date. Some contracts may not require the counterparty to post collateral. In such circumstances, the Baupost Partnerships would not receive collateral from the counterparty to cover the Baupost Partnerships' exposure. In addition, the Baupost Partnerships may transact with counterparties located in certain jurisdictions outside the United States where local laws and regulations may not permit the Baupost Partnerships to exercise the full range of its rights under its derivatives contracts or exercise them promptly, which could negatively impact the value of the derivatives.

Derivatives transactions are also subject to documentation risk, including the risk that the parties may disagree as to the proper interpretation of the terms of the applicable contract. If such a dispute occurs, the cost and unpredictability of the legal proceedings required for the Baupost Partnerships to enforce their contractual rights may lead the Baupost Partnerships to decide not to pursue their claims against the other counterparty. The Baupost Partnerships thus assume the risk that they may be unable to obtain payments owed to them under contracts relating to OTC transactions or that those payments may be delayed or made only after the Baupost Partnerships have incurred the costs of litigation. Furthermore, with respect to some derivatives contracts, the counterparty is given sole discretion over determinations that affect the value of the contract or the parties' rights and obligations under the contract.

To the extent the Baupost Partnerships engage in derivatives transactions with a single counterparty or a small number of counterparties, the Baupost Partnerships have greater exposure to the risks described in the foregoing paragraphs, and a default by a single counterparty could have an adverse effect on the Baupost Partnerships and their assets and investment returns.

Certain derivatives transactions that may be used by the Baupost Partnerships, including certain interest rate swaps and certain credit default index swaps, are required to be cleared. In a cleared derivatives transaction, a Partnership's counterparty to the transaction is a central derivatives clearing organization, or clearing house, rather than a bank or broker. Since the Baupost Partnerships are not members of a clearing house, and only members of a clearing house can participate directly in the clearing house, the Baupost Partnerships have entered into cleared

derivatives transactions through clearing members that are futures commission merchants and members of the clearing houses. The Baupost Partnerships make and receive payments owed under cleared derivatives transactions (including margin payments) through their accounts at clearing members. A Partnership's clearing members guarantee that Partnership's performance of its obligations to the clearing house. In contrast to bilateral derivatives transactions, in some cases following a period of advance notice to a Partnership, clearing members can generally require termination of existing cleared derivatives transactions at any time and increase the amount of margin required to be provided by the Partnership to the clearing member for any cleared derivatives transaction above the amount of margin required by the clearing house or clearing member. Clearing houses also have broad rights to increase margin requirements for existing transactions and to terminate transactions. Any such termination or increase could interfere with the ability of a Partnership to pursue its investment strategy. Also, a Partnership is subject to execution risk if it enters into a derivatives transaction that is required to be cleared (or that Baupost expects to be cleared), and no clearing member is willing to clear the transaction on that Partnership's behalf. In that case, the transaction might have to be terminated, and such Partnership could lose some or all of the benefit of any increase in the value of the transaction after the time of the trade.

Some types of cleared derivatives are required to be executed on an exchange or on a swap execution facility. A swap execution facility is a trading platform where multiple market participants can execute derivatives transactions by accepting bids and offers made by multiple other participants in the platform. While this execution requirement is designed to increase transparency and liquidity in the cleared derivatives market, trading on a swap execution facility can create additional costs and risks for the Baupost Partnerships. For example, swap execution facilities typically charge fees, and if a Partnership executes derivatives transactions on a swap execution facility through a broker intermediary, the intermediary may impose fees as well. Transactions executed on a swap execution facility are subject to the rules of that facility, and a Partnership could be held liable for violations of such rules. As a member of a swap execution facility, a Partnership is subject to the jurisdiction of the swap execution facility with respect to the enforcement of its rules and to the ability of the swap execution facility to inspect such Partnership's books and records. Also, a Partnership may indemnify a swap execution facility, or a broker intermediary who executes cleared derivatives on a swap execution facility on such Partnership's behalf, against any losses or costs that may be incurred as a result of such Partnership's transactions on the swap execution facility.

The Dodd-Frank Wall Street Reform and Consumer Protection Act and regulations thereunder require real-time public reporting of swap transaction and pricing data, including for swaps that are executed on a swap execution facility. "Swap data repositories" are required to disseminate publicly certain data that they receive as soon as technologically practicable, subject to a time delay for certain large swap transactions ("block trades"). The minimum size of block trades and the time delay before dissemination of information regarding block trades has been a subject of

concern in the markets, because public reporting of a large transaction immediately following execution could have an adverse impact on the ability of a party to the transaction to enter into offsetting transactions to hedge its exposure. The Commodity Futures Trading Commission has adopted rules that seek to mitigate this concern by establishing threshold swap notional amounts for off-exchange swaps, above which public reporting is delayed and the mandatory trade execution requirement falls away. While block trades that would otherwise have been subject to the trade execution requirement are required to be executed pursuant to the rules of a swap execution facility, they are not required to be executed through the swap execution facility's order book or request-for-quote system. The Baupost Partnerships have authorized Baupost to enter into block trades on behalf of the Baupost Partnerships from time to time.

Rules issued by U.S., EU and other regulators globally impose various margin requirements (the "Margin Rules") on all swaps that are not centrally cleared, including the establishment of minimum amounts of margin that must be posted. Although the Margin Rules are intended to increase the stability of the derivatives market, the overall amount of margin that the Baupost Partnerships will be required to post to swap counterparties may increase by a material amount, and as a result the Baupost Partnerships will not be able to put such capital to the uses that they otherwise would. Moreover, the margin requirements for both cleared and uncleared OTC derivatives may require that Baupost, in order to maintain its exemption from commodity pool operator registration under CFTC Rule 4.13(a)(3), limit the Baupost Partnerships' hedging transactions or exposure to synthetic investments, in either case potentially adversely affecting the Baupost Partnerships' ability to mitigate risk. Such restrictions would be inapplicable if Baupost ultimately registers as a commodity pool operator.

These and other new rules and regulations could, among other things, further restrict the Baupost Partnerships' ability to engage in, or increase the cost to the Baupost Partnerships of, derivatives transactions, for example, by making some types of derivatives no longer available to the Baupost Partnerships, increasing margin or capital requirements or otherwise limiting liquidity or increasing transaction costs. The costs of derivatives transactions are expected to increase as clearing members raise their fees so as to cover the costs of additional capital requirements and other regulatory changes applicable to the clearing members and when rules imposing mandatory minimum margin requirements on OTC derivatives become effective.

Forward Contracts

The Baupost Partnerships have entered and may from time to time enter into forward contracts and options thereon, including non-deliverable forwards. The principals who deal in the forward contract market are not required to continue to make markets in such contracts. There have been periods during which certain participants in forward markets have refused to quote prices for forward contracts or have quoted prices with an unusually wide spread between the price at which they were prepared to buy and that at which they were prepared to sell. The imposition of credit controls or price risk limitations by governmental authorities may limit such forward trading to

less than that which Baupost would otherwise recommend, to the possible detriment of the Baupost Partnerships. In their forward trading, the Baupost Partnerships will be subject to the risk of the failure of, or the inability or refusal to perform with respect to their forward contracts by, the principals with which the Baupost Partnerships trade. The Baupost Partnerships' assets on deposit with such principals will also generally not be protected by the same segregation requirements imposed on certain regulated brokers in respect of customer funds on deposit with them. Baupost may order trades for the Baupost Partnerships in such markets through agents. Accordingly, the insolvency or bankruptcy of such parties could also subject the Baupost Partnerships to the risk of loss.

Contracts for Differences

The Baupost Partnerships have entered and may enter into contracts for differences ("CFDs"). CFDs are privately negotiated contracts between two parties, buyer and seller, stipulating that the seller will pay to, or receive from, the buyer the difference between the nominal value of the underlying instrument at the opening of the contract and that instrument's value at the end of the contract. The underlying instrument may be a single security, stock basket or index. A CFD can be set up to take either a short or long position on the underlying instrument. The buyer and seller are both required to post margin, which is adjusted daily. The buyer will also pay to the seller a financing rate on the notional amount of the capital employed by the seller less the margin deposit. As is the case with trading any financial instrument, there is the risk of loss associated with trading a CFD. CFDs may be considered illiquid, including if the underlying instrument is illiquid because the liquidity of a CFD is based on the liquidity of the underlying instrument. A further risk is that adverse movements in the underlying security will require the posting of additional margin. CFDs also carry counterparty risk (i.e., the risk that the counterparty to the CFD transaction may be unable or unwilling to make payments or to otherwise honor its financial obligations under the terms of the contract). If the counterparty were to do so, the value of the contract may be reduced. Entry into a CFD transaction may, in certain circumstances, require the payment of an initial margin and adverse market movements against the underlying stock may require additional margin payments. To the extent that there is an imperfect correlation between the return on a Partnership's obligation to its counterparty under the CFDs and the return on related assets in its portfolio, the CFD transaction may increase a Partnership's financial risk.

Options

The Baupost Partnerships have sought and may seek to increase their current return by writing covered call and put options on securities, commodities and/or other assets. When the Baupost Partnerships write an option they receive a premium, which increases the Baupost Partnerships' returns if the option expires unexercised or is closed out at a net profit. When the Baupost Partnerships write a call option, they give up the opportunity to profit from any increase in the price of the underlying asset above the exercise price of the option; when they write a put option, the Baupost Partnerships take the risk that they will be required to purchase the underlying asset

from the option holder at a price above the current market price of the asset. The Baupost Partnerships may also from time to time buy and sell combinations of put and call options on the same underlying asset to earn additional income. The Baupost Partnerships may also buy options to enter into swap transactions ("swaptions"). In exchange for an option premium, the buyer of a swaption obtains the right, but not the obligation, to enter into a specified swap agreement with an issuer on a specified future date. The agreement will specify whether the buyer of the swaption will be a fixed-rate receiver (such as a call option on a bond) or a fixed-rate payer (such as a put option on a bond). The Baupost Partnerships may also buy and sell put and call options and buy swaptions for hedging purposes. The Baupost Partnerships' use of these strategies may be limited by applicable law.

Futures and Related Options

The Baupost Partnerships have bought and sold and may, to the extent permitted by applicable law, buy and sell futures contracts and related options. A futures contract is an agreement between two parties to buy and sell a specific quantity of a commodity (including a securities index or an interest-bearing security) for a set price at a future date. The Baupost Partnerships may also buy and sell call and put options on futures or on securities indexes in addition to or as an alternative to purchasing or selling futures contracts, or, to the extent permitted by applicable law, to earn additional income.

The use of futures and options involves certain special risks. Futures and options transactions involve costs and may result in losses. Certain risks arise because of the possibility of imperfect correlations between movements in the prices of futures and options and movements in the prices of the underlying securities, securities index, currencies or other commodities or of the securities or currencies in the Baupost Partnerships' portfolios that are the subject of the hedge (to the extent the Baupost Partnerships use futures and options for hedging purposes). The successful use of futures and options further depends on Baupost's ability to forecast market or interest rate movements correctly. Other risks arise from the Baupost Partnerships' potential inability to close out their futures or options positions, and there can be no assurance that a liquid secondary market will exist for any futures contract or option at a particular time. The use of futures and options for purposes other than hedging is regarded as speculative. Certain regulatory requirements may also limit the Baupost Partnerships' ability to engage in futures and options transactions.

The Baupost Partnerships may from time to time buy and sell non-U.S. futures contracts and related options. Transactions in markets located outside the United States, including markets formally linked to a U.S. market, may be subject to regulations that offer different or diminished protection to the Baupost Partnerships, including a limited ability to enforce agreements.

Swaps, Caps, Floors, Collars and Credit Spread Trades

The Baupost Partnerships have entered into and may enter into swaps, caps, floors, collars and credit spread trades on various securities, securities indexes, interest rates, prepayment rates, commodities, non-U.S. currencies or other financial instruments or indexes, including varying combinations thereof, for both hedging and non-hedging purposes, including, without limitation, to maximize returns (including to take advantage of the relative value across interest rates, credit spreads, volatility levels, commodities indexes, commodities subsectors, individual commodities, currency exchange rates, and equity indexes), to preserve a return or spread on a particular investment or portion of its portfolio, to gain exposure to a particular market or market segment, to protect against (or to opportunistically benefit from) currency fluctuations, as a duration management technique, or to protect against any increase in the price of securities the Baupost Partnerships anticipate purchasing at a later date. Transactions consisting of multiple components may be more volatile, less liquid and more difficult to price accurately than less complex securities or more traditional derivatives transactions.

Swaps typically involve an exchange of obligations by two parties. For example, interest rate swaps involve the exchange of respective rights to receive interest, such as an exchange of fixed-rate payments for floating-rate payments. Currency swaps involve the exchange of respective rights to make or receive payments in specified currencies. In an equity swap, the counterparty generally agrees to pay the Baupost Partnerships the amount, if any, by which the notional amount of the equity swap contract would have increased in value had it been invested in the underlying stock or stocks plus the dividends that would have been received on those stocks. The Baupost Partnerships agree to pay to the counterparty a floating rate of interest (typically based on a Reference Rate) on the notional amount of the equity swap contract plus the amount, if any, by which that notional amount would have decreased in value had it been invested in such stock or stocks. Therefore, the return to the Baupost Partnerships on any equity swap contract should be the gain or loss on the notional amount plus dividends on the underlying stocks less the interest paid by the Baupost Partnerships on the notional amount less premium paid, if any. The Baupost Partnerships may also from time to time enter into the opposite side of equity swap contracts, which are known as "reverse equity swaps."

The Baupost Partnerships may from time to time also enter into credit default swaps, including credit default swaps on mortgage-backed securities (such as residential mortgage-backed securities), asset-backed securities, corporate debt, municipal debt or sovereign debt. In a credit default swap, one party pays what is, in effect, an insurance premium through a stream of payments to another party in exchange for the right to receive a specified return in the event of a default (or similar events) by a third party on its obligations. Typically, in a credit default swap, the Baupost Partnerships may pay a premium and, in return, have the right to put certain bonds or loans to the counterparty upon default by the issuer of such bonds or loans (or similar events) and to receive in return the par value of such bonds or loans (or another agreed upon amount). In addition, the

Baupost Partnerships could also receive the premium and be obligated to pay a counterparty the par value of certain bonds or loans upon a default (or similar event) by the issuer. A credit default swap transaction on mortgage-backed and asset-backed securities, corporate debt, municipal debt or sovereign debt would be subject to the same risks as those described herein with respect to such securities, in addition to the risks associated with swap transactions.

Payments under a swap contract may be made at the conclusion of the contract or periodically during its term. The Baupost Partnerships thus assume the risk that they may be delayed in or prevented from obtaining payments owed to them pursuant to swap contracts. To address this risk with respect to interest rate swaps, the Baupost Partnerships will usually enter into interest rate swap contracts on a net basis, which means that the two payment streams (one from the Baupost Partnerships to the counterparty, one to the Baupost Partnerships from the counterparty) are netted out, with the Baupost Partnerships receiving or paying, as the case may be, only the net amount of the two payments. Interest rate swaps do not involve the delivery of securities, other underlying assets or principal. Accordingly, the risk of loss with respect to interest rate swaps entered into on a net basis would be limited to the net amount of the interest payments that the Baupost Partnerships are contractually obligated to make. If the other party to an interest rate swap defaults, the Baupost Partnerships' risk of loss consists of the net amount of interest payments that the Baupost Partnerships are contractually entitled to receive. In contrast, currency swaps and other types of swaps may involve the delivery of the entire principal value of one designated currency or financial instrument in exchange for the other designated currency or financial instrument. Therefore, the entire principal value of such swaps may be subject to the risk that the other party will default on its contractual delivery obligations. Credit default swaps generally only require payment in the event of an actual default or credit event, as opposed to a credit downgrade or other indication of financial difficulty.

Swap contracts are individually negotiated, and their terms are not uniform across contracts. The Baupost Partnerships may be unable to close out their obligations under a particular swap contract. Moreover, unless the Baupost Partnerships choose to, and are successful in, negotiating transfer rights, then swaps contracts are ordinarily non-transferable. Under such circumstances, the Baupost Partnerships might be able to negotiate another swap contract with a different counterparty to offset the risk associated with the first swap contract. However, unless the Baupost Partnerships are able to negotiate such an offsetting swap contract, the Baupost Partnerships could be subject to continued adverse developments, even after Baupost has determined that it would be prudent to close out or offset the first swap contract.

The use of swaps involves investment techniques and risks different from and potentially greater than those associated with ordinary portfolio securities transactions. If Baupost is incorrect in its expectations of market values, interest rates or currency exchange rates, the investment performance of the Baupost Partnerships would be less favorable than it would have been if this investment technique were not used. Certain swaps that the Baupost Partnerships may use can

also have the effect of creating leverage and thus can give rise to many of the same risks associated with borrowing funds or trading on margin. Because certain non-U.S. markets may be closed for all practical purposes to U.S. investors such as the Baupost Partnerships, the Baupost Partnerships have invested and expect to invest indirectly in such markets through swap transactions and would therefore be subject to the risks described above with respect to investments in non-U.S. securities. Swap transactions are also subject to the same counterparty risk as that described for derivatives generally.

The use of swaps involves the risk that the price of the swap used by the Baupost Partnerships to calculate Net Asset Value does not accurately reflect its fair value, which could result in an overstatement or understatement of the Net Asset Value of the Baupost Partnerships to the extent that the price of the swap diverges from its fair value. Many swaps are complex and may be valued based on quotes given by swap counterparties, who have adverse interests to the Baupost Partnerships with respect to the value of such swaps. In certain cases, the Baupost Partnerships' swap counterparty may be the only source of value quotations for a swap, while in other cases, multiple quotations may be available. There are also different methodologies that may be used to determine the value of a credit default swap and credit default swap spreads may be wide. As a result of the foregoing factors, the Baupost Partnerships may not be able to close out swaps at the price used by the Baupost Partnerships to calculate Net Asset Value.

If the assets, if any, pledged to the counterparty in connection with a Partnership entering into a swap agreement decrease in value, such Partnership may be required to pledge additional collateral to the lender in the form of cash or securities to avoid liquidation of those assets or potential liquidations of the leveraged asset. Also, under certain circumstances, if a swap counterparty undervalues the Baupost Partnerships' interests in a swap, it could require the Baupost Partnerships to transfer greater amounts of collateral to the counterparty than if the swap was valued at fair value. The rights of any counterparty to the Baupost Partnerships to receive payments may be senior to the rights of the investors, and the terms of the Baupost Partnerships' swap agreements may contain provisions that limit certain activities of the Baupost Partnerships.

Caps, floors and collars are variations on swaps. The purchase of a cap entitles the purchaser to receive payments from the party selling the cap to the extent that a specified index exceeds a predetermined interest rate or amount. The purchase of an interest rate floor entitles the purchaser to receive payments from the party selling the floor to the extent that a specified index falls below a predetermined interest rate or amount. A collar is a combination of a cap and a floor that preserves a certain return within a predetermined range of interest rates or values. Caps, floors and collars are similar in many respects to OTC options transactions, and may involve investment risks that are similar to those associated with options transactions and options on futures contracts. A credit spread trade is an investment position relating to a difference in the prices or interest rates of two securities or currencies, where the value of the investment position is determined by

movements in the difference between the prices or interest rates, as the case may be, of the respective securities or currencies.

Other Derivative Instruments

The Baupost Partnerships may invest in other derivative instruments that are not presently contemplated for use or that are currently not available, but that may be developed. Special risks may apply to instruments that are invested in by the Baupost Partnerships in the future that cannot be determined at this time. Certain swaps, options and other derivative instruments may be subject to various types of risks, including market risk, liquidity risk, the risk of non-performance by the counterparty, including risks relating to the financial soundness and creditworthiness of the counterparty, legal risk and operations risk.

General Risks Associated with Investments in Digital Assets

The Baupost Partnerships may invest in digital assets and derivatives that reference digital assets (which includes, but is not limited to, virtual currencies, cryptocurrencies, and digital coins and tokens). The Baupost Partnerships may also purchase digital assets on a spot basis in order to settle or hedge derivative transactions that reference digital assets. The investment characteristics of digital assets generally differ from those of traditional currencies, commodities or securities.

Importantly, digital assets are not backed by a central bank or a national, supra-national or quasi-national organization, and many are not backed by any dedicated collateral or reserves and may not give rise to any claims against an issuer or any party. Rather, digital assets are market-based and a digital asset's value is determined by (and may fluctuate significantly and often, according to) a wide range of factors, including supply and demand factors; the number of merchants that accept it; the value that various market participants place on it through their mutual agreement, barter or transactions; interruptions in service or failures of major trading venues; actual or predicted government regulation impacting digital assets; actual or purported fraud related to digital assets or other "hacks" or thefts of digital assets; and investment and trading activities of large investors. Valuation is further complicated by the lack of centralized pricing sources, which may create pricing discrepancies between trading venues.

Transfers of digital assets are verified and recorded on distributed ledgers or "blockchains." An incorrect transfer of digital assets (due to theft, human error or otherwise) generally will not be reversible, and the Baupost Partnerships may not be capable of seeking compensation for any such transfer. Further, various digital assets are controllable only by the possessor of unique private keys relating to the digital wallet addresses in which the digital assets are held. The theft, loss or destruction of a private key required to access a digital asset is often irreversible, and the Baupost Partnerships would generally not be able to access the digital assets held in such digital wallet as a result.

Several events or factors can result in disruptions of digital asset markets and, therefore, markets for derivatives or other financial products that reference digital assets, including cyberattacks, theft, fraud or other operational losses at trading venues, wallet providers or other platforms or intermediaries; commencement of insolvency proceedings in respect of one or more trading venues; suspension or limitation on trading in digital assets, including intervention by a government authority; sudden changes in the legal, regulatory or tax treatment of digital assets or related derivatives, including heightened enforcement activity or the imposition of limits on owning or trading in digital assets; decreases in the amount of mining activity or collusion between the miners and validators that confirm digital asset transactions; and the announcement or occurrence of changes in a digital asset's underlying technology protocols (such as a "fork"), initiation or discontinuation of use or support by a significant merchant, investor or other market participant, trading venue or other intermediary.

The occurrence of any of the above could adversely affect the Baupost Partnerships' investments in digital assets or derivatives that reference digital assets.

**Risks Relating to Market Conditions Generally**

General Economic and Market Conditions

The success of the Baupost Partnerships' activities will be affected by general economic and market conditions, such as interest rates, availability of credit, credit defaults, inflation rates, economic uncertainty, changes in laws (including laws relating to taxation of the Baupost Partnerships' investments), trade barriers, currency exchange controls and national and international political circumstances (including wars, terrorist acts or security operations). These factors may affect the level and volatility of the prices and the liquidity of the Baupost Partnerships' investments. Volatility or illiquidity could impair the Baupost Partnerships' profitability or result in losses. The Baupost Partnerships may maintain substantial trading positions that can be adversely affected by the level of volatility in the financial markets.

Governmental Interventions

Extreme volatility and illiquidity in markets has led to, and may lead to, extensive governmental interventions in equity, credit and currency markets. Generally, such interventions are intended to reduce volatility and precipitous drops in value. In certain cases, governments have intervened on an "emergency" basis, suddenly and substantially eliminating market participants' ability to continue to implement certain strategies or manage the risk of their outstanding positions. In addition, these interventions have typically been unclear in scope and application, resulting in uncertainty. It is difficult to predict when these restrictions will be imposed, what the interim or permanent restrictions will be and/or the effect of such restrictions on the Baupost Partnerships' strategies.

Potential Interest Rate Increases

The United States has experienced a sustained period of historically low interest rate levels. In recent years, however, short-term and long-term interest rates have risen. The uncertainty of the U.S. and global economy, changes in U.S. government policy, and changes in the federal funds rate, increase the risk that interest rates will remain volatile in the future. Sustained future interest rate volatility may cause the value of the fixed income securities held by the Baupost Partnerships to decrease.

Discontinuation of LIBOR

It is expected that the U.S. dollar London Interbank Offered Rate ("LIBOR"), which is commonly used as a reference rate within various financial contracts (any such rate, a "Reference Rate"), will not be published after June 30, 2023 (other than the one-week and two-month tenors, which will not be published after the year 2021). In anticipation of the end of LIBOR, the United States and other countries are currently working to replace LIBOR with alternative Reference Rates. As a general matter, the expected discontinuation of LIBOR may significantly impact financial markets; specifically, discontinuation may impact financial contracts to which the Baupost Partnerships are a party. Generally, the transition to alternative Reference Rates may (i) cause the value of a Reference Rate to be uncertain or to be lower or more volatile than it would otherwise be; (ii) result in uncertainty as to the functioning, liquidity or value of certain financial contracts; (iii) involve actions of regulators or rate administrators that adversely affect certain markets or specific financial contracts; and (iv) impact the strategy, products, processes, legal positions and information systems of market participants, including the Baupost Partnerships and their counterparties. With respect to financial contracts to which the Baupost Partnerships are a party, including corporate and municipal bonds and loans, consumer loans, bank loans, floating rate debt, certain asset-backed securities, and interest rate swaps and other derivatives, any such contract that has a maturity that extends beyond June 2023 and uses LIBOR as a Reference Rate (other than contracts that include curative fallback language or other curative mechanisms) may need to be renegotiated, the process of which will consume resources of the Baupost Partnerships and may result in disputes among counterparties, the result of which may be adverse to the Baupost Partnerships. Considered in their entirety, the impacts of the discontinuation of LIBOR on financial markets generally and on the specific financial contracts to which the Baupost Partnerships are a party may adversely affect the performance of the Baupost Partnerships.

Sanctions

The United States or other nations or governmental entities could impose sanctions on a country, group or individual that limit or restrict foreign investment, the movement of assets or other economic activity or that otherwise restrict the ability to conduct business with the target party. Before making investments, Baupost conducts due diligence that it deems reasonable and

appropriate based on the facts and circumstances applicable to each investment, including, where applicable, an assessment of whether the investment might be subject to sanctions. In addition, Baupost monitors the risk of sanctions with respect to existing investment holdings on an ongoing basis. Despite the risk assessment and monitoring undertaken by Baupost, investments may become subject to economic sanctions laws and regulations of various jurisdictions, which could adversely impact the Baupost Partnerships. At any given time, whether under applicable law, by contractual commitment or as a voluntary risk management measure, the Baupost Partnerships may be required, or elect, to comply with various sanctions programs, including the Specially Designated Nationals and Blocked Persons List and Sectoral Sanctions programs administered by OFAC, the sanctions regimes administered by subsidiary organs of the United Nations Security Council, the Sanctions Orders of the Cayman Islands (including as extended to the Cayman Islands by Order of the government of the United Kingdom from time to time), and the Restrictive Measures adopted by the European Union. Some sanctions that may apply to the Baupost Partnerships prohibit or restrict dealings with particular identified persons. Other potentially applicable sanctions programs broadly prohibit or restrict dealings in certain countries or territories or with individuals and entities located in such countries or territories. In addition to such current sanctions, additional sanctions may be imposed in the future. Such sanctions may be imposed with little or no advance warning or "safe harbor" for compliance and may be ambiguous, including as to the scope of financial activities that regulators may ultimately deem to be covered by the sanctions.

Sanctions may adversely affect the Baupost Partnerships in various ways, including by preventing or inhibiting the Baupost Partnerships, or Baupost on the Baupost Partnerships' behalf, from making certain investments, forcing the Baupost Partnerships to divest from investments previously made, and leading to substantial reductions in the revenues, profits and value of companies in which the Baupost Partnerships have invested. In addition, if the Baupost Partnerships or Baupost, were to violate or be deemed in violation of any such sanction, it could face significant legal and monetary penalties. Depending on the scope and duration of a particular sanctions program, compliance by the Baupost Partnerships may result in a material adverse effect on the Baupost Partnerships' and the investors' investments therein.

Competition; Availability of Investments

Many of the markets in which the Baupost Partnerships invest are extremely competitive for attractive investment opportunities. As a result, there can be no assurance that Baupost will be able to identify or successfully pursue attractive investment opportunities in such environments.

Volatility Risk

The Baupost Partnerships' investment program involves and, in the future, may involve the purchase and sale of relatively volatile securities and/or investments in volatile markets.

Fluctuations or prolonged changes in the volatility of such securities and/or markets can adversely affect the price of investments held by the Baupost Partnerships.

Systemic Risk

Financial intermediaries, such as clearing houses, banks, securities firms and exchanges with which the Baupost Partnerships interact, as well as the Baupost Partnerships, are all subject to systemic risk that could impact the Baupost Partnerships and the markets for the securities in which the Baupost Partnerships seek to invest. Systemic risk is the risk of broad financial system stress or collapse triggered by the default of one or more financial institutions that results in a series of defaults by other interdependent financial institutions.

**Certain Risks Related to Management of the Baupost Partnerships**

Reliance on Key Personnel

The investment performance of the Baupost Partnerships depends largely on the skill of key personnel of Baupost, including, in particular, Mr. Seth Klarman and other senior personnel who make investment decisions with respect to the Baupost Partnerships' investments. Competition in the financial services industry for experienced and capable investment professionals is intense. If any of its key personnel were to leave Baupost, it might not be able to find equally desirable replacements, and the performance of the Baupost Partnerships could be adversely affected.

Reliance on Third Party Managers

Because the Baupost Partnerships have invested and expect to invest in other pooled vehicles and joint ventures, the management of certain investments may be primarily performed by a party other than Baupost. Although the Baupost Partnerships will often have the ability to influence the management of such investment vehicles, there can be no assurance that Baupost will always be able to exercise control over the underlying investment decisions. Since investments decisions of such vehicles are made by the investment advisers independently of each other, at any particular time, one investment vehicle may be purchasing securities of an issuer whose securities are being sold by another investment vehicle, and a Partnership could indirectly incur certain transaction costs without accomplishing any net investment result.

Valuation of Investments

Many of the investments made by the Baupost Partnerships are illiquid, complex and difficult to value. Actual realized returns on investments will depend among other things on the value of the securities at the time of disposition, any related transaction costs and the manner of sale. Accordingly, the actual realized return on investments will likely differ, sometimes materially, from the values presented to the investors.

Material Nonpublic Information

Baupost personnel possess confidential or material nonpublic information regarding certain issuers of public financial instruments, for example, information received as a result of entering into confidentiality agreements regarding public companies. If Baupost personnel receive material nonpublic information with respect to such issuers, the Baupost Partnerships may be prohibited by law, policy or contract, for a period of time from (i) establishing an initial position or taking any greater position in such issuer, (ii) unwinding a position in such issuer, or (iii) transacting in other investment opportunities; such prohibitions may have an adverse effect on the Baupost Partnerships.

Cybersecurity Risk

As part of its business, Baupost processes, stores and transmits large amounts of electronic information, including information relating to the transactions of the Baupost Partnerships and personally identifiable information of investors in the Baupost Partnerships. Similarly, service providers of Baupost and the Baupost Partnerships, including certain service providers located outside of the United States, process, store and transmit such information. Baupost has procedures and systems in place that it believes are reasonably designed to protect such information and prevent data loss and security breaches. However, such measures cannot provide absolute security. The techniques used to obtain unauthorized access to data, disable or degrade service, or sabotage systems change frequently and may be difficult to detect for long periods of time. Hardware or software acquired from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information security. Network connected services provided by third parties to Baupost may be susceptible to compromise, leading to a breach of Baupost's network. Baupost's systems or facilities may be susceptible to employee error or malfeasance, government surveillance, or other security threats. On-line services provided by Baupost to investors may also be susceptible to compromise. Breach of Baupost's information systems may cause information relating to the transactions of the Baupost Partnerships and personally identifiable information of investors to be lost or improperly accessed, used or disclosed. In general, cyber-attacks are deliberate, but unintentional events may have similar effects. Cyber-attacks include, among other things, stealing or corrupting data maintained online or digitally, preventing legitimate users from accessing information or services on a website, releasing confidential information without authorization, and causing operational disruption.

The service providers of Baupost and the Baupost Partnerships are subject to the same electronic information security threats as Baupost. If a service provider fails to adopt or adhere to adequate data security policies, or in the event of a breach of its networks, information relating to the transactions of the Baupost Partnerships and personally identifiable information of investors may be lost or improperly accessed, used or disclosed.

The loss or improper access, use or disclosure of Baupost's or the Baupost Partnerships' proprietary information may cause the Baupost or the Baupost Partnerships to suffer, among other things, financial loss, the disruption of its business, liability to third parties, regulatory intervention or reputational damage. Any of the foregoing events could have a material adverse effect on the Baupost Partnerships and their investors' investments therein.

The same cybersecurity risks described above are present for issuers of securities in which the Baupost Partnerships invest, including issuers in which the Baupost Partnership may own a "control" position. Such risks could result in material adverse consequences for such issuers and may cause the Baupost Partnerships' investments in such securities to lose value.

## Item 9. Disciplinary Information

There is one disciplinary event regarding a Partner of Baupost, as follows:

Between 2003 and 2005, private funds managed by Baupost made three French real property investments alongside third parties through Luxembourg companies (the "Luxembourg Entities"). Thomas Blumenthal, a Partner, was appointed as a director of the Luxembourg Entities. Subsequent to the 2006 sale of these investments, the French Tax Administration ("FTA") opened tax audits of the Luxembourg Entities. The FTA alleged that the Luxembourg Entities were not eligible for beneficial tax treatment under the France-Luxembourg tax treaty, and thus were required to pay income tax in France. One of the three Luxembourg Entities successfully proved in French court that no tax was due. The remaining two Luxembourg Entities appealed the FTA's assessment to the French Supreme Tax Court. On March 31, 2017, the French Supreme Tax Court ruled against these Luxembourg Entities. In 2011, the FTA referred for investigation potential charges against all of the directors of the two remaining Luxembourg Entities, including Mr. Blumenthal, alleging that these Luxembourg Entities and their directors had engaged in tax fraud as a result of the failure by these Luxembourg Entities to pay income tax in France. On January 11, 2017, Mr. Blumenthal was notified that a Magistrate Judge had charged the directors of these two Luxembourg Entities, including Mr. Blumenthal, with committing criminal tax fraud.

Following a trial, the court on June 20, 2018 convicted the directors of the two Luxembourg entities, including Mr. Blumenthal, of criminal tax fraud and sentenced each director to a fine and a suspended sentence. As to Mr. Blumenthal, the order of conviction imposed a fine of approximately US$43,000, together with a suspended sentence of four years. The directors of the Luxembourg entities, including Mr. Blumenthal, were also determined to be jointly and severally liable as a civil matter for the balance of the income taxes and related interest and penalties determined to be due in respect of the Luxembourg Entities. The Baupost Partnerships that owned these investments paid their portion of the taxes, interest and penalties in 2017; the balance was subsequently satisfied.

Mr. Blumenthal acted in good faith for the benefit of the Baupost Partnerships, having followed advice from prominent international tax advisors in connection with these investments, and Mr. Blumenthal appealed the judgment in 2018. While Baupost has always strongly disagreed with this verdict and views the conviction as unwarranted, Mr. Blumenthal withdrew the appeal in June 2021 with the full support of Baupost.

The Baupost Partnerships did not bear any portion of the appellate defense costs or the additional tax obligation and will not bear any portion of the fine. The verdict does not impact Mr. Blumenthal's continuing role as a Partner at Baupost.

**Item 10. Other Financial Industry Activities and Affiliations**

Neither Baupost nor any of its management persons is registered, or has an application pending to register, as a broker-dealer, registered representative of a broker-dealer, futures commission merchant, commodity pool operator, commodity trading advisor, or associated person of any of the foregoing entities. If Baupost recommends or selects other investment advisers for the Baupost Partnerships, Baupost will not receive compensation directly or indirectly from those advisers, nor will Baupost have other business relationships with those advisers that create any material conflicts of interest.

As disclosed in Item 4, Baupost Partners serves as the profit sharing general partner to the Baupost Partnerships. Additionally, pursuant to a Sourcing Agreement, Baupost Group International LLP, an affiliate of Baupost, provides advisory services to Baupost by augmenting the sourcing of potential investments in Europe.

**Item 11. Code of Ethics, Participation or Interest in Client Transactions and Personal Trading**

Baupost strives to adhere to the highest industry standards of conduct based on principles of professionalism, integrity, honesty and trust. In seeking to meet these standards, we maintain a Code of Ethics (the "Code"). The Code incorporates the following general principles applicable to all employees:

- employees have a fiduciary obligation to and must at all times place the interests of the Baupost Partnerships first;
- all personal securities transactions must be conducted in a manner consistent with the Code and any actual or potential conflicts of interest must be escalated;
- employees must not take any inappropriate advantage of their positions;

- information concerning the identity of securities and financial circumstances of the Baupost Partnerships, including the Baupost Partnerships' investors, must be kept confidential; and

- independence in the investment decision-making process must be maintained at all times.

Additionally, the Code (i) governs the personal securities transactions of Baupost's employees and immediate family/household members; and (ii) requires all employees to report any violations of the Code to Baupost's chief compliance officer.

The Code restricts or prohibits certain personal investment transactions by employees and their immediate family/household members in any account in which they have beneficial ownership or any account in which they have investment discretion, including family charitable foundations (collectively, the "Accounts"). Employees must receive approval prior to transacting in securities in their Accounts (other than certain exempted securities, which include direct obligations of the United States of America, commercial paper, shares issued by money market funds, and shares issued by open-end mutual funds).

The Code prohibits employees defined as "Investment Personnel" (generally, those employees who make investment recommendations on behalf of the Baupost Partnerships) from purchasing "public securities" (as defined in the Code). The Code does not prohibit purchases of interests in the Baupost Partnerships, and certain key personnel of Baupost have significant interests in the Baupost Partnerships.

The restrictions of the Code do not prohibit employees from investing in or having exposure to public and private investments that Baupost has recommended to the Baupost Partnerships, subject to the preclearance requirements of the Code. Similarly, employees and their charitable foundations may also invest in transactions offered to but rejected by the Baupost Partnerships. Employees or their charitable foundations may invest in securities alongside the Baupost Partnerships subject to the preclearance requirements of the Code. In these circumstances, the employees (or indirectly their charitable foundation) may benefit from their knowledge of the evaluation, investigation, and due diligence undertaken by Baupost on behalf of the Baupost Partnerships. Furthermore, employees and/or their charitable foundation will not share or reimburse the relevant Baupost Partnership and/or Baupost for any expenses incurred in connection with the investment opportunity.

In addition, the Baupost Partnerships from time to time invest in securities of companies that Investment Personnel acquired for their own Account prior to joining Baupost. While the interests of Investment Personnel generally align with those of the Baupost Partnerships, such persons may have differing interests with respect to those investments creating potential conflicts of interest.

Baupost will provide a copy of the Code to any investor or potential investor upon request.

Transactions with Affiliates

The LP Agreements do not prohibit the Baupost Partnerships from participating in transactions in which Baupost or any investor is directly or indirectly interested (including, subject to compliance with the Advisers Act, any transaction between the Baupost Partnerships and Baupost or an affiliate thereof). For example, Baupost or its affiliates could engage in commercial transactions with businesses in which the Baupost Partnerships have an interest, such as commercial or residential real estate leases or transactions for goods and services provided by portfolio companies owned by the Baupost Partnerships. In connection with such transactions, the Baupost Partnerships, on the one hand, and Baupost and its affiliates, on the other hand, may have conflicting interests.

Baupost may also face conflicts of interest in connection with purchase or sale transactions (involving an investment by a Partnership) with an affiliate of such Partnership (including the other Baupost Partnerships), including with respect to the consideration offered by, and the obligation of, Baupost and such other affiliate. Although the Baupost Partnerships have not historically engaged in principal transactions between the Baupost Partnerships and Baupost or an affiliate thereof, they may do so and in such circumstances Baupost will either (i) seek the advance consent of the majority in interest of the investors of the relevant Partnership(s) or (ii) appoint an independent body (such as, for example, an advisory board or another person or persons), which shall be comprised of at least two persons, and may consist of investors or third-parties, to represent the interests of the investors. Baupost shall inform investors if it appoints any such independent body and shall identify its members to investors. The advance consent of such independent body or of the majority in interest of the investors shall be deemed to be the consent of a Partnership, including for purposes of the Advisers Act. Any such independent body or person(s), and the members thereof, will not owe any fiduciary or other duties to the investors or the Partnership and may be indemnified out of a Partnership's assets.

Business between Portfolio Companies and Other Investments

Certain portfolio companies or other investments of the Baupost Partnerships occasionally receive and pay for products or services from other portfolio companies or other investments. To the extent that the decision to obtain the products or services is made by Baupost, Baupost will perform reasonable diligence to ascertain that the products or services meet Baupost's selection criteria including, but not limited to, the nature, quality, cost and level of relevant expertise. The costs of the products and services will be borne by the relevant portfolio companies or other investments.

Cross Trades

While it has not historically done so, Baupost may determine that it would be in the best interests of some or all of the Baupost Partnerships to engage in a cross trade, such as the transfer of a financial instrument or an illiquid investment from one Partnership to another, for a variety of

reasons, including tax considerations, liquidity considerations, to rebalance the portfolios of the Baupost Partnerships or to reduce transaction costs that may arise in an open market transaction. If Baupost decides to effect a cross trade between some or all of the Baupost Partnerships, Baupost will have determined that the trade is in the best interests of all of the Partnerships involved. In executing cross trades, Baupost could face a potential conflict of interest with respect to the allocation of investment opportunities.

A cross trade between two Partnerships may occur as an "internal cross" that is reflected in the books and records of each Partnership at a price determined in accordance with Baupost's valuation policy. If Baupost effects an internal cross on behalf of some or all of the Baupost Partnerships, Baupost will not receive any commission in connection with the completion of the transaction. Alternatively, Baupost may execute cross trades with the assistance of a broker-dealer that executes and books the transaction at the close of the market on the day of the transaction, and the applicable Partnerships may pay such broker-dealer a commission in respect thereof.

Baupost may cause the Baupost Partnerships to engage in cross trades with respect to Illiquid Assets. Baupost is responsible for determining the fair value of the Illiquid Assets of the Baupost Partnerships; however, there is no guarantee that the value determined by Baupost with respect to a particular asset will represent the value that will be realized by the Baupost Partnerships on the eventual disposition of the related investment or that would be realized upon an immediate disposition of the investment. There is a risk that Baupost's valuation determination with respect to Illiquid Assets subject to a cross trade could operate to the detriment of one client in favor of another. To the extent that Baupost has engaged an independent valuation expert in connection with the valuation of an Illiquid Asset for purposes unrelated to an internal cross trade and the Baupost Partnerships intend to engage in an internal cross trade with respect to such Illiquid Asset, the Baupost Partnerships will execute the internal cross trade based on the same valuation used for such other unrelated purpose (or, if there have been material developments since the time of such prior valuation, Baupost intends to utilize an independent valuation expert to determine the price at which such internal cross trade will occur). Baupost has a conflict of interest in a range of situations, including for example where the applicable cross trades entered into by a Partnership (i) are with other of the Baupost Partnerships in which Baupost and its affiliates and employees own substantial interests or (ii) involve circumstances where Baupost's compensation is tied to a greater degree to the performance of one party to the cross trade.

Allocations of Investment Opportunities and Sales

Certain prospective investments may be appropriate for several of the Baupost Partnerships, and, because of Baupost's, its affiliates' and employees' investments in the Baupost Partnerships, there may be a conflict of interest in the allocation of investment opportunities among the Baupost Partnerships. The allocation of such investments among the Baupost Partnerships is determined by Baupost in its best judgment and in its sole discretion taking into account such factors as it believes relevant. Generally, allocations of liquid purchases among the Baupost Partnerships are

made pro rata based on each Partnership's available buying capacity, which is determined based on projected available cash. Allocations of Illiquid Asset purchases among the Baupost Partnerships are generally made pro rata, based on each Partnership's available buying capacity, and where applicable, restricted investment capacity (both at the discretion of Baupost). Allocations of sales are generally made pro rata based on the ownership of the existing position by the Baupost Partnerships.

Baupost may in its sole discretion depart from the general allocation principles set forth herein, including when doing so would, in Baupost's sole discretion, be appropriate based upon certain factors, including but not limited to the relative size of the Baupost Partnerships, current holdings, availability of cash for investment, the size of the investments generally, limitations concerning illiquid investments, tax considerations, regulatory restrictions, legal considerations and the need to re-size risk. Other allocation methodologies used by Baupost can include allocations based on the relative Net Asset Values of the Baupost Partnerships and order size, among others. Although Baupost and its affiliates intend to allocate investment opportunities and sales in a manner that is fair to all the entities involved, there can be no assurances that an investment opportunity that comes to the attention of Baupost and its affiliates would not be allocated wholly or primarily to some Baupost Partnerships, with another Partnership being unable to participate in such investment opportunity or participating only on a limited basis.

A particular investment may be bought or sold for only one or some of the Baupost Partnerships, or at different times for more than one but less than all of the Baupost Partnerships. Likewise, a particular investment may be bought for one or more of the Baupost Partnerships when one or more of the other Baupost Partnerships are selling the investment. It is also possible that one or more of the Baupost Partnerships may engage in short sales of an investment owned or being purchased by other Baupost Partnerships or vice versa. There can be no assurance that a Partnership will not receive less (or none) of a certain investment than it would otherwise receive if Baupost did not have to allocate such investment among multiple Baupost Partnerships.

Allocation of Hedges and Follow-on Investments

Allocations of portfolio-level hedge purchases among the Baupost Partnerships are generally made pro rata based on their Net Asset Values. Net Asset Value, for allocation purposes, is the most current period-end Partnership Net Asset Value, which may be adjusted for estimated or projected activity based on guidelines established by Baupost. Allocations of purchases specific to an existing investment, such as investment hedges or follow-on investments, are generally made pro rata based on the allocation of that existing position across the Baupost Partnerships. Follow-on investments include, but are not limited to, additional investments made by a joint venture or pooled investment vehicle in which a Partnership is already invested. Accordingly, allocations may be fixed for discrete investments made by such joint ventures or pooled investment vehicles over a period of several years.

Baupost may, in its sole discretion, elect to treat a follow-on investment as a new investment for allocation purposes. These investments will be allocated based on the then-current allocation methodology (rather than based on ownership of the prior related investment), which may result in, depending on the ownership of certain Baupost Partnerships, a greater allocation to Baupost Partnerships with employee investors than might otherwise be the case.

A Partnership may make two or more investments that have hedging properties with respect to one another. Because of the varying participation by investors in restricted investments and new issues, among other factors, investors may participate in these types of complementary investments in a proportion that may vary significantly from that of other investors, or may participate in only one of the underlying investments and not the other(s). As a result, such investors may not obtain Baupost's intended hedging ratio for the applicable investments.

Co-Investments Offered by the Baupost Partnerships

Generally, Baupost does not offer co-investment opportunities to any investor in the Baupost Partnerships and no investor in the Baupost Partnerships is entitled to a co-investment opportunity by reason of being an investor in the Baupost Partnerships. Baupost has in the past, and may in the future, determine that it would be beneficial to the Baupost Partnerships to allocate a portion of an investment opportunity that would have otherwise been available to the Baupost Partnerships to one or more co-investors, such as third-party investment advisers and their affiliated investment funds. It is possible that such co-investors may experience financial, legal or regulatory difficulties and may, from time to time, have economic, tax, regulatory, contractual or other business interests or goals that are inconsistent with those of the Baupost Partnerships and as a result, may take a different view from Baupost as to appropriate strategy for an investment or may be in a position to take a contrary action to the Baupost Partnerships' investment objectives.

In connection with these investments, the Baupost Partnerships may initially bear investment-related expenses attributable to such co-investors. In these circumstances, Baupost requires that the co-investors agree to reimburse the Baupost Partnerships for these expenses.

Sell Downs

Baupost has in the past, and may in the future, enter into transactions with third-parties to reduce, or "sell down," all or a portion of certain investments held by one or more of the Baupost Partnerships. The sales price for such transactions will be mutually agreed to by Baupost and the purchaser(s); however, determinations of sales prices involve a significant degree of judgment by Baupost and Baupost is not obligated to solicit competitive bids for such sales transaction or to seek the highest available price, which means Baupost may not obtain the highest price for the transaction. There can be no assurance, in light of the performance of the investment following such a transaction, that such transaction will ultimately prove to be the most profitable or advantageous course of action for the applicable Baupost Partnership(s).

Co-Investments Offered to the Baupost Partnerships

Baupost Partnership have in the past, and may in the future, invest in third-party investment funds that offer co-invest opportunities. These co-investments will generally be allocated based on the then-current allocation methodology (rather than based on ownership of the relevant underlying third-party investment fund), which may result in, depending on the ownership of certain Baupost Partnerships, a greater allocation to Baupost Partnerships with employee investors than might otherwise be the case.

Tax Considerations

Baupost monitors the tax characteristics of the Baupost Partnerships' investment activities and portfolio on an on-going basis. Occasionally, the timing and terms of investment and trading decisions are influenced by the expected tax results of those decisions for the Baupost Partnerships and their investors as a whole. There can be no guarantee that the decisions will result in the expected tax results, or that all investors would necessarily benefit from the decisions in light of their individual tax situations. In seeking to conduct their investment activities in a tax efficient manner, the Baupost Partnerships could be exposed to risks that would not have occurred in the absence of tax considerations, such as changes in market prices and liquidity. Investors that are exempt in whole or in part from taxation may not benefit from decisions that take into account tax considerations but may still bear any risks of such considerations.

Investments in Different Layers of the Capital Structure and Related Conflicts

The Baupost Partnerships may invest in different layers of the capital structure of an issuer, and may make investments in one or more issuers or instruments that may involve economic conflict with respect to one another. For example, upon liquidation or bankruptcy of an issuer, distributions are generally made in a manner providing priority to, respectively, secured creditors, unsecured creditors, preferred equityholders and common equityholders. The Baupost Partnerships may at times hold both debt and equity of the same issuer, and may hold different types of debt and different types of equity. Additionally, the Baupost Partnerships may invest in the equity or debt of an issuer while at the same time investing in certain rights or claims against such issuer. Further, any of the foregoing investments may be restricted investments or new issues, while others may not be, resulting in a potential conflict given that not all investors participate in, or fully participate in, restricted investments or new issues.

In certain circumstances, such as when an issuer defaults on its debt or seeks protection from creditors in bankruptcy, a conflict of interest can arise in that the action taken to protect the interest of one set of security holders may be at the potential detriment of other holders of the same issuer's securities or instruments. Depending on the extent to which such an investor participates in restricted investments and on the timing of their capital contributions and withdrawals, the returns

of an individual investor, including investors who are Baupost employees, may vary from the returns of a Partnership generally and of those experienced by other investors.

If the Baupost Partnerships own securities and instruments of the same issuer in different levels of seniority, action taken for the benefit of some of the Baupost Partnerships may favor that set of the Baupost Partnerships at the expense of another. Baupost will endeavor to manage any such potential conflict(s) in a manner that is fair to the Baupost Partnerships, by, among other things, making investment decisions for each investing Partnership on independent grounds based on the economics and investment objectives of such investing Partnership.

Other Benefits

From time to time, Baupost and its employees receive or may receive benefits and/or discounts in connection with their activities on behalf of the Baupost Partnerships that are not shared with the Baupost Partnerships or their investors and that do not offset the management fees received by Baupost. These benefits include discounted hotel room rates at certain real estate properties that the Baupost Partnerships own through joint ventures and may include discounts for consumer products sold by certain portfolio companies owned by the Baupost Partnerships.

## Item 12. Brokerage Practices

It is Baupost's policy, in placing each transaction for a Baupost Partnership, to seek "best execution." Accordingly, Baupost will seek to obtain an outcome for a purchase or sale of a security that is in the best long-term economic interests of the Baupost Partnerships, subject to the circumstances of the transaction and the quality and reliability of the executing broker or dealer. Best execution is not measured solely by reference to commission rates or price. Baupost may cause the Baupost Partnerships to pay a broker a higher commission rate or price than what another broker might charge if it believes that the difference in cost is reasonably justified in seeking what is in the best long-term economic interests of the Baupost Partnerships.

Baupost believes that for the vast majority of securities transactions for the Baupost Partnerships, best execution is not quantifiable, but rather is a set of quality standards—a trading process that seeks to maximize the value of a Partnership's portfolio over the course of time, given the stated investment objectives and circumstances. In short, Baupost seeks to achieve the best overall end result for each Partnership, the key components of which include a dedicated staff aware of Baupost's fiduciary obligations, up-to-date information and systems, reputable broker-dealers and sufficient oversight. Maximizing long term profit for the Baupost Partnerships takes precedence over short-term goals of cost efficiency in connection with individual trades.

Factors

In determining whether a particular broker or dealer is likely to provide best execution, Baupost takes into account all factors that it deems relevant to the broker's or dealer's execution capability, including:

- The overall reputation, experience and financial stability of the broker-dealer;
- The quality of the broker-dealer relationship with Baupost, including the attention, consistency and quality of trading personnel with whom transactions are conducted;
- Research services, including the quality of proprietary research and investment ideas that ultimately become meaningful positions in a Partnership's portfolio of investments and the ability of the broker-dealer to provide access to company management and industry specialists, subject to the restrictions and limitations discussed in the Research Services Section below;
- The broker-dealer's trading expertise, including the ability to minimize total trading costs and to trade without impacting the market;
- The ability, when possible, to maintain Baupost's anonymity when executing a trade;
- The quality of execution, including the broker-dealer's infrastructure in areas such as order handling, clearing and settlement;
- The ability to provide ad hoc information or other services;
- The quality of service rendered by the broker-dealer in prior transactions; and
- The belief that the broker-dealer charges a fair and reasonable fee for each trade, and that Baupost has been treated fairly and honestly in prior trades.

In determining whether a particular broker or dealer is likely to provide best execution in a particular transaction, Baupost will also take into account the following factors:

- The price, including commissions or spread;
- The size of the transaction;
- The timing of the transaction, taking into account market prices and trends;
- The nature of the market for the security;
- Whether the broker-dealer has the ability to transact in the share size and price sought by Baupost, and the ability to in fact execute and settle the trade;

- Whether the broker-dealer is informed about the investment and involved in the particular market in which the investment trades; and
- The difficulty of execution for the type of security and market in which it trades.

In addition, Baupost considers the use of electronic trading tools such as crossing networks and execution algorithms when placing trades on behalf of the Baupost Partnerships, particularly when trading equities. These tools enable Baupost to transact passively and source liquidity anonymously. However, when the trade size is substantial, the requirements unusual or the issue illiquid, any of which may necessitate additional time for the trade to be executed, Baupost will often rely on the expertise and ability of individuals to assess and react to market conditions as they develop. In addition, when purchasing or selling OTC securities with market makers, Baupost generally seeks market makers it believes to be actively and effectively trading the security being purchased or sold.

<u>Research and Other Services</u>

Many securities firms offer to provide investment managers (such as Baupost) a variety of services and benefits that go beyond execution, clearance and settlement of transactions. These services and benefits include such things as (i) the broker-dealer firms' proprietary research reports and analytical products, (ii) information and advice about market conditions and individual securities, (iii) investment opportunities that may be attractive for the Baupost Partnerships, (iv) opportunities to meet with company management and (v) capital introduction services whereby Baupost may be afforded the opportunity to make a presentation regarding its services to certain qualified investors identified by the securities firm. Investment managers often seek to recognize broker-dealers who provide these services or benefits by directing transactions to these broker-dealers or by paying higher commissions to these broker-dealers than would otherwise be appropriate.

A potential conflict of interest is presented in every instance where an investment manager chooses to place a client trade with a broker-dealer that has furnished the manager with services or benefits other than order execution, clearance and settlement (unless the manager has paid the full value of such services and benefits using the manager's own assets). The conflict arises because the manager receives a benefit for which it does not need to pay and has an incentive to select a broker-dealer based on its own interest in receiving such benefits, as opposed to the client's interest in receiving most favorable execution. Because of this conflict of interest, the law places strict limits on investment managers' discretion to place transactions with broker-dealers who are providing services or benefits to the investment manager. Baupost attempts to minimize such potential conflicts through the use of commission-sharing arrangements whereby a portion of the commission dollars generated through Baupost's normal trading activity are aggregated and periodically allocated through a third party to firms that provide research services to Baupost. Research services that Baupost may receive include research reports, investment ideas, access to issuer management and investment conferences and other information that assists Baupost in

providing investment advisory services to the Baupost Partnerships. Baupost finds commission sharing arrangements to be valuable because, by separating the execution and research capabilities of different broker-dealers, Baupost can concentrate trading with those broker-dealers that provide superior execution while still obtaining valuable research from other broker-dealers and research providers. Baupost's use of commissions to pay for research and related services is undertaken pursuant to the safe-harbor provisions of Section 28(e) of the Securities Exchange Act of 1934 and in accordance with SEC interpretive guidance regarding the application of such provisions.

In addition, broker-dealers may provide Baupost with access to proprietary research reports that are used for the Baupost Partnerships. Since these and other products and services are generally made available by broker-dealers as part of a bundled business package to Baupost (which may or may not use such products and services) without regard to rates of commission or volume of business, it is Baupost's understanding that such broker-dealers do not set discrete prices for such products and services. Accordingly, Baupost does not separately compensate such broker-dealers for the provision of such services and does not believe that it pays a premium for such broker-dealers' services.

Baupost does trade with certain broker-dealer firms that provide valuable research and other services. However, the only circumstances in which Baupost, in selecting a broker-dealer to execute a transaction for a Baupost Partnership, may take into account research services or benefits provided by the broker-dealer are when Baupost has determined, in good faith, that the amount of commission on the transaction is reasonable in relation to the value of the research or other benefit from the broker-dealer, viewed in terms of either that transaction or Baupost's overall responsibilities to the Baupost Partnerships.

Baupost does not recommend, request or require that a Baupost Partnership execute transactions through a specific broker-dealer or permit any Baupost Partnership to direct Baupost's transactions to a particular broker, nor does Baupost consider, when selecting broker-dealers, whether Baupost or a related person receives client referrals from a broker-dealer or a third party.

Trade Aggregation

Baupost will aggregate the Baupost Partnerships' orders and place the aggregated order with a single broker or dealer for execution. The Baupost Partnerships that participate in an aggregated trade each generally pay their pro rata share of the total cost of the trade and receive their pro rata share of the proceeds. From the standpoint of a single Partnership, simultaneous identical portfolio transactions for such Partnership and other Baupost Partnerships may decrease the prices received, and increase the prices required to be paid, by that Partnership for its portfolio sales and purchases. In effecting transactions, it may not always be advisable, or consistent with the investment objectives of the Baupost Partnerships, to take or liquidate the same investment positions at the same time or at the same prices.

Trade Errors

Baupost has a Trade Error Policy to handle trade errors (as defined in the Trade Error Policy) that may arise in connection with placing trades on behalf of the Baupost Partnerships. Baupost attempts to correct errors as soon as practicable after discovery. If a Partnership realizes a gain from a trade error or the correction thereof, the gain will remain with that Partnership. If a Partnership realizes a loss, Baupost will evaluate the trade error in light of the standard of care owed to that Partnership under the relevant LP Agreement. Accordingly, the cost of trade errors will be borne by the Baupost Partnerships unless attributable to the fraud, gross negligence or willful misconduct of Baupost.

**Item 13. Review of Accounts**

Baupost's investment staff monitor the Baupost Partnerships' investments on an ongoing basis. Additionally, Baupost, as managing general partner of the Baupost Partnerships, performs a monthly review of the Baupost Partnerships' accounts and ensures that each Partnership is in compliance with its LP Agreement. As part of this review, Baupost verifies that all income and loss items, management fee and profit sharing obligation are allocated appropriately to each investor in the applicable Partnership. This allocation review is performed by Baupost's Portfolio Valuations, Accounting and Reporting department under the supervision of the Portfolio Controller and is overseen by Baupost's Chief Financial Officer.

Baupost engages a third-party administrator to maintain the official books and records for the Baupost Partnerships. Administrative services include cash and position confirmation, pricing confirmation, Net Asset Value calculation, investor income allocations, fee calculations, and preparation of limited partner account statements.

The financial statements of the Baupost Partnerships are prepared and audited in conformity with accounting principles generally accepted in the United States ("GAAP") at each calendar year-end.

Investors in the Baupost Partnerships are provided with regular written or electronic reports communicating information relating to capital account value, Baupost Partnership Net Asset Value, portfolio allocation, and performance. Regular reporting is provided at the capital account level, at each Partnership, and across the Baupost Partnerships with substantially similar investment objectives. Investors receive various written or electronic reports on a monthly, quarterly and annual basis. Reports are distributed in hard copy or electronically, mainly through Baupost's website. Certain Baupost Partnerships receive additional Partnership-level reporting. Investors who are members of Baupost's Advisory Board may receive additional information.

Finally, Baupost holds periodic investor webcasts and meetings to provide updates on investment activity and performance of the portfolio. These oral communications are generally archived for a limited period on Baupost's website for the benefit of investors.

## Item 14. Client Referrals and Other Compensation

Baupost does not compensate any person for client referrals, nor does Baupost receive any economic benefit from someone who is not a client for providing investment advice or other advisory services to the Baupost Partnerships.

## Item 15. Custody

Under Rule 206(4)-2 of the Advisers Act (often referred to as the "Custody Rule"), Baupost is deemed to have custody of client funds or securities in any circumstances under which (i) Baupost actually possesses funds or securities, (ii) Baupost is authorized to withdraw funds or securities from the Baupost Partnerships (for example, to deduct fees), or (iii) Baupost or a related person serves in a legal capacity, such as general partner, which affords Baupost access to funds or securities of the Baupost Partnerships.

Accordingly, Baupost has engaged a PCAOB-registered independent accounting firm to perform an annual audit of the financial statements of each Partnership prepared in accordance with GAAP, which are distributed to all investors within 120 days of each Partnership's fiscal year end.

In addition, the assets of each Partnership are generally held (other than certain privately offered securities) with "qualified custodians" (as defined in the Custody Rule), which may be a broker-dealer, bank or another type of institution, as required by the Custody Rule. These qualified custodians do not send account statements to investors in the Baupost Partnerships.

## Item 16. Investment Discretion

Baupost has discretionary authority over all assets it manages for the Baupost Partnerships as described in the respective LP Agreements. This discretionary authority is conferred on Baupost pursuant to each Partnership's LP Agreement.

## Item 17. Voting Client Securities

Baupost has sole authority to vote the Baupost Partnerships' securities, and Baupost adheres to an internal Proxy Voting Policy that governs Baupost's practices in exercising this voting authority. Baupost's policy is to vote proxies on securities held by the Baupost Partnerships in a manner that seeks to maximize their long-term economic interests, although Baupost considers both the short-term and long-term implications of each proposal in determining the optimal vote.

If Baupost should determine that a material conflict of interest exists in voting a proxy (*e.g.,* if an employee of Baupost may personally benefit if the proxy is voted in a certain manner), Baupost's procedures provide for the Proxy Voting Committee to convene and to determine the appropriate vote. If the Proxy Voting Committee is unable to reach a decision, Baupost, at its own expense,

will engage a competent third party to determine the appropriate vote based on Baupost's Proxy Voting Policy.

Information regarding how Baupost votes proxies is available to the Baupost Partnerships. Additionally, the Baupost Partnerships have access to Baupost's Proxy Voting Policy.

**Item 18. Financial Information**

Baupost does not require or solicit prepayment of any fees six months or more in advance and does not have any financial condition that would impair its ability to meet contractual commitments to the Baupost Partnerships.

# Exhibit 24

**Date of Issuance**
**June 16, 2014**

**PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

**SAFETY AND ENFORCEMENT DIVISION** **RESOLUTION ESRB-4**
**June 12, 2014**

# R E S O L U T I O N

RESOLUTION ESRB-4. Directs Investor Owned Electric Utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.

PROPOSED OUTCOME: This Resolution will cause Investor Owned Electric Utilities to take remedial measures to reduce the likelihood of fires associated with or threatening their facilities during the current drought.

SAFETY CONSIDERATIONS: This Resolution directs Investor Owned Electric Utilities to take measures to reduce the likelihood of fires associated with or threatening their facilities, which will increase the safety to the general public in both forested areas and at urban–rural interfaces.

ESTIMATED COST: Unknown.

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## SUMMARY

On January 17, 2014, Governor Edmund G. Brown, Jr. proclaimed a State of Emergency and directed state officials to take actions to mitigate against conditions that could result from a drought.[1] In conjunction with his Emergency Proclamation, the Governor stated in his press release: "We can't make it rain, but we can be much better prepared for the terrible consequences that California's drought now threatens, including dramatically less water for our farms and communities and increased fires in both urban and rural areas."[2]

On May 6, 2014, President Obama issued a press release, entitled: "Fact Sheet: What Climate Change Means for Regions across America and Major Sectors of the

[1] http://gov.ca.gov/news.php?id=18368.

[2] Id.

Economy."[3] The press release was accompanied by the third U.S. National Climate Assessment (NCA), the most comprehensive scientific assessment ever generated of climate change and its impacts across every region of America and major sectors of the U.S. economy.[4] In President Obama's press release, he made clear that Climate Change is already having severe impacts. Thus, he stated that we must build a "sustainable future for our kids and grandkids," and we must further act "to reduce the greenhouse-gas pollution that is driving climate change … to cope with changes in climate that are already underway."[5] In an overview of the NCA, President Obama referred to Southwest region of the United States as the hottest and driest region in the United States, which is already a parched region that is expected to get hotter and, in the southern half, significantly drier. "Drought and increased warming foster wildfires and increased competition for the scarce water resources for people in ecosystems."[6]

On May 14, 2014, Governor Edmund G. Brown, Jr. proclaimed a State of Emergency in San Diego County. The proclamation cited major wildfires which were "difficult to contain" in part due to "extremely dry conditions." The proclamation also noted that "the fires have damaged and continue to threaten critical infrastructure, including power lines."[7]

In this context, where Climate Change has facilitated and exacerbated numerous wildfires, which have damaged and could continue to threaten the critical infrastructure of the utilities, the Commission finds that an emergency exists. Therefore, the instant Resolution directs Investor Owned Electric Utilities - i.e., Pacific Gas and Electric

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[3] http://www.whitehouse.gov/the-press-office/2014/05/06/fact-sheet-what-climate-change-means-regions-across-america-and-major-se.

[4] http://nca2014.globalchange.gov/.

[5] http://www.whitehouse.gov/the-press-office/2014/05/06/fact-sheet-what-climate-change-means-regions-across-america-and-major-se.

[6] Id.

[7] http://gov.ca.gov/news.php?id=18527. Under Rule 13.9 of our Rules of Practice and Procedure, the Commission may take official notice of matters that may be judicially noticed by the courts pursuant to Cal. Evid. Code §§ 450, *et seq.* Pursuant to Cal. Evid. Code § 452(c), judicial notice may be taken of official acts of the executive department of the United States or of any state of the United States. Clearly, as the heads of the executive branches of the United States and of the State of California, respectively, President Obama's press releases and his release of official reports, as well as the Emergency Proclamations of Governor Jerry Brown, Jr., constitute official acts. In addition, in light of the overwhelming evidence presented by the scientific community, we find that the effects of greenhouse gas emissions on Climate Change, and the extremely dry conditions, droughts and large number of wildfires, which have resulted from the greenhouse gas emissions and which California is currently experiencing, are not matters reasonably subject to dispute. Therefore, these factual matters may be judicially noticed pursuant to Cal. Evid. Code § 452(h). We therefore have provided the websites of these official acts and undisputable facts.

Company (PG&E), Southern California Edison Company (SCE); San Diego Gas and Electric Company (SDG&E); PacifiCorp; Liberty Utilities, and Bear Valley Electrical Service (hereinafter, the "IOUs") - to take additional remedial measures to reduce the likelihood of fires associated with or threatening their facilities during the current drought.

## BACKGROUND

### Climate Change

We have long recognized that Climate Change would have adverse impacts in the State of California. In Decision (D.) 07-01-039, the Commission implemented Senate Bill (SB) 1368 by adopting greenhouse gas (GHG) emission performance standards (EPS). The purpose of the EPS was to significantly limit the GHG emissions allowed from the California IOUs' future procurement contracts for electric power. In D.07-01-039, we stated:

> "As the Legislature found in SB 1368, global warming will have devastating impacts on the economy, health and environment of the State of California."[8]

More specifically, we stated:

> "GHG emissions contribute to climate change. By increasing the number of extremely hot days, and the 'frequency, duration, and intensity of conditions conducive to air pollution formation, oppressive heat, and wildfires,' the public health of Californians could be dramatically affected."[9]

Thereafter, in a series of Commission decisions aimed at reducing GHG emissions through our jurisdiction over the California IOUs, the Commission has tried to significantly reduce the GHG emissions caused by the IOUs' own generation power plants or their procurement of electric power.[10] The Governor, Legislature, the Commission, the California Air Resources Board (CARB) and virtually every other state

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[8] D.07-01-039, *mimeo.*, at 262, Finding of Fact 218.

[9] D.07-01-039, *mimeo.*, at 214. (Internal citations omitted.)

[10] *See, e.g.,* D.12-12-032, D.12-11-015, D.11-12-036, D.10-12-036, and D.09-09-047 (funding and promoting energy efficiency programs to reduce the demand for electricity); D.11-12-019, D.11-07-031, and D.10-09-046 (promoting the California Solar Initiative); and D.09-12-047 (self-generation incentive program).

agency have taken significant actions to reduce GHG emissions and to attempt to slow down the effects of Climate Change.[11]

**The Firestorms in 2007**

After a disastrous series of wildfires in October of 2007, some of which were reportedly caused by the electric power lines of California IOUs, the Commission in 2008 issued an Order Instituting Rulemaking (R.) 08-11-005 designed to adopt new regulations to reduce the risk of further fire hazards (hereinafter "the Fire Safety OIR"). As the Commission explained in D.14-02-015, *mimeo.,* at 3 - 4:

> In October 2007, strong Santa Ana winds swept across Southern California and caused dozens of wildfires. The resulting conflagration burned more than 780 square miles, killed 17 people, and destroyed thousands of homes and buildings. Hundreds of thousands of people were evacuated at the height of the fire siege. Transportation was disrupted over a large area for several days, including many road closures. Portions of the electric power network, public communication systems, and community water sources were destroyed.
>
> Several of the worst wildfires were reportedly ignited by power lines. These included the Grass Valley Fire (1,247 acres), the Malibu Canyon Fire (4,521 acres), the Rice Fire (9,472 acres), the Sedgewick Fire (710 acres), and the Witch Fire (197,990 acres). The total area burned by these five power-line fires was more than 334 square miles.
>
> In response to the widespread devastation, the Commission issued Order Instituting Rulemaking (R.) 08-11-005 to consider and adopt regulations to reduce the fire hazards associated with overhead power lines and aerial communication facilities in close proximity to power lines. Most of the Commission's regulations regarding the construction, operation, and maintenance of overhead utility facilities are in General Order (GO) 95 and GO 165. A major goal of these GOs is to minimize public safety hazards, including fire hazards, associated with overhead utility facilities.

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[11] In Assembly Bill (AB) 32, CARB was made the lead agency to oversee these efforts. However, the Commission, like other agencies, was required to assist and coordinate with CARB in order to reduce GHG emissions from sources under the Commission's jurisdiction, such as the IOUs. Cal. Health and Safety Code §§ 38501(g), 38561(a) and 38562(b).

> R.08-11-005 was initially divided into two phases. Phase 1 focused on fire-prevention measures that could be implemented in time for the 2009 autumn fire season in Southern California. Phase 1 concluded with the issuance of Decision (D.) 09-08-029. Phase 2 addressed matters that required more time to consider and implement. Phase 2 concluded with the issuance of D.12-01-032.

**The Pace of Climate Change Is Increasing**

Although the Commission has known that GHG emissions contribute to Climate Change, the catastrophic consequences of Climate Change have now become a reality and the drought conditions threaten California with more frequent and extensive wildfires. The purpose of President Obama's May 6, 2014 press release, accompanied by the third NCA, was "*to underscore the need for urgent action to combat threats from climate change, protect American citizens and communities today*, and build a sustainable future … [President Obama's Climate Action] Plan acknowledges that even as we act to reduce the greenhouse-gas pollution that is driving climate change, we must empower the Nation's communities, businesses, and individual citizens with the information *they need to cope with changes in climate that are already underway*." (Emphasis added).

The Governor's Emergency Proclamations on January 17, 2014 on the drought conditions throughout California and on May 14, 2014 concerning the San Diego Fires and their threat to power lines are consistent with President Obama's message that Climate Change is increasingly occurring and we need further efforts to protect the public from its adverse effects today. We had previously found that the "fire season" in Southern California has been regularly occurring in the Fall each year. That was why the Commission had expedited procedures in its Phase 1 of its Fire Safety OIR, so that the additional fire safety rules could be in place by the 2009 Fall fire season.[12]

In light of these climate changes, which increase the wildfire threats to the IOUs' critical infrastructure much earlier than in previous years and more significantly throughout the year, the Commission has good cause to find that waiting 30 days for comments could cause significant harm to the public. Under Rule 14(c)(9) of the Commission's Rules of Practice and Procedure, the Commission reaffirms that public necessity supports a shortened notice period for one-time comments instead of waiting the full 30 days for comments. Therefore, the Commission shortened the time for comments on the Draft Resolution, such that comments were due by June 9, 2014.

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[12] D.09-08-029, *mimeo.*, at 2.

## DISCUSSION

### It Is Vital to Implement Mitigation Measures Against the Increased Wildfire Risk Caused by the Current Drought and Climate Change

On January 17, 2014, Governor Edmund G. Brown Jr. proclaimed a State of Emergency and directed state officials to take actions to mitigate against conditions that could result from a drought.[13] In conjunction with his Emergency Proclamation, the Governor stated in his press release, "we can be much better prepared for the terrible consequences that California's drought now threatens, including dramatically less water for our farms and communities and increased fires in both urban and rural areas."[14]

### Commission's Response to State of Emergency

In response to the Governor's directive, on February 18, 2014, Denise Tyrrell, Acting Director of the Safety and Enforcement Division (SED), sent a letter to the IOUs. The first directive that Acting Director Tyrrell instructed the IOUs to comply with was to take practicable measures necessary to reduce the likelihood of fires. Specifically, Acting Director Tyrrell's letter states:

> Due to the increased chance of large and devastating fires in California, I hereby direct you and your company to take all practicable measures necessary to reduce the likelihood of fires started by your facilities. This may include, but is not limited to the following actions:
>
> - Increased inspections in fire threat areas
> - Re-prioritization of corrective action items
> - Modification to protective schemes.[15]

The Commission generally supports these directives. More specifically, the IOUs should do the following: increase vegetation inspections and remove hazardous, dead and sick trees and other vegetation near the IOUs' electric power lines and poles; share resources with the California Department of Forestry and Fire Protection (CalFire) to staff lookouts adjacent to the IOUs' property; and clear access roads under power lines for fire truck access.

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[13] http://gov.ca.gov/news.php?id=18368.

[14] Id.

[15] See, e.g., Attachment 1, Letter dated February 18, 2014, from Denise Tyrrell, Acting Director of the Safety and Enforcement Division to Patrick M. Hogan, PG&E's Vice President Asset Management, Electric Operations.

Acting Director Tyrrell's letter also offered the Safety and Enforcement Division's assistance to IOUs for reducing the likelihood of wildfires, if, for example, and IOU discovers a Safety Hazard, as defined by General Order 95, Rule 18-B and a third party is restricting the IOU's access to remedy the situation.[16]

We fully support the above directive, and by this Resolution, order the IOUs to comply. We note that nothing in this Resolution expands or restricts any requirements that are currently applied to utilities, including General Order 95. We further require that IOUs confer with Acting Director Tyrrell as to her designations of the appropriate SED staff to receive such notifications.

**Subsequent Events Support Acting Director Tyrrell's February 18, 2014 Directive**

On March 26, 2014, George Gentry, Executive Officer of the California Board of Forestry and Fire Protection, sent a letter to the Commission stating, in part:

> [T]he Board unanimously directed me to send a letter that not only endorses the action of the CPUC, but strongly encourages the CPUC to support funding the Utilities at the appropriate levels to conduct this important electric vegetation management work.
>
> …
>
> The Utilities can perform significant work that helps to ensure public safety. Given the appropriate resources, a significant public private partnership could be forged. We support timely completion of that work in the face of the extreme conditions presented by this drought.[17]

On May 14, 2014, Governor Edmund G. Brown Jr. proclaimed a State of Emergency in San Diego County, which cited major wildfires which were "difficult to contain" in part due to "extremely dry conditions" and which further noted that "the fires have damaged and continue to threaten critical infrastructure, including power lines."[18]

Furthermore, CalFire posts fire statistical data on their website[19] for fires to which CalFire has responded. This data shows that CalFire has responded to over 200 more

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[16] See, e.g., Attachment 1, Letter dated February 18, 2014, from Denise Tyrrell, Acting Director of the Safety and Enforcement Division to Patrick M. Hogan, PG&E's Vice President Asset Management, Electric Operations.

[17] See Attachment 2, Letter dated March 26, 2014 from George Gentry to the Commission.

[18] http://gov.ca.gov/news.php?id=18527.

[19] See http://cdfdata.fire.ca.gov/incidents/incidents_statsevents.

fires in 2014 as compared to 2013, during the same time period (i.e., January 1, 2014 through May 24, 2014), and over 500 more fires have occurred when compared to the five-year average for the same interval. Moreover, this period analyzed above is well before the Fall, when the fire season in Southern California has historically occurred as a result of even drier vegetation and stronger gusts of wind (i.e., the Santa Ana winds).[20]

**The Vicious Cycle of Wildfires**

The problem with wildfires is not limited to the destruction they could cause to the utilities' infrastructure (which threatens the safety and reliability of these services), let alone the threat the wildfires pose to the lives of people, the homes and businesses in the vicinity of the wildfires. The large or fast-spreading wildfires further threaten to destroy significant acres of forests, which otherwise are one of the major offsetting remedies to GHG emissions.

In D.06-12-032, the Commission recognized the importance of forests in combatting Climate Change, when PG&E proposed its pilot Climate Protection Tariff (CPT) to provide offsets in advance of CARB's implementation of cap and trade pursuant to AB 32. The Commission further stated in D.06-12-032, *mimeo.,* at 39 – 40:

> We are satisfied that forestry is an adequate sector on which to focus initial CPT program efforts, given that the California Climate Action Registry (CCAR) has already developed a protocol for forest-based projects. Moreover, no party objects to PG&E contracting for GHG reductions in the forestry sector. . . .
> [W]e agree with PG&E and other parties that conserving forests has positive environmental benefits beyond GHG emissions reductions, in the areas of water quality, habitat conservation, and prevention of stream erosion. Thus, we accept forestry as the first focus of PG&E's CPT project.

The President's Climate Action Report of June 2013 provides further guidance for the current climate situation.[21] At page 15, the Report identifies efforts to "reduce wildfire risk by removing extra brush and other flammable vegetation around

[20] As stated, above, in the Fire Safety OIR, the Commission adopted different phases, so that by the end of Phase 1, the Commission could implement additional fire reduction standards before fire season began in the Fall season of 2009. *See* D.09-08-029, *mimeo.,* at 2.

[21] http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

critical areas such as water reservoirs."[22] Moreover, recognizing that forests play a significant role in the mitigation of Climate Change, at page 11 the Report states:

> "America's forests play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. In the face of a changing climate and increased risk of wildfire, drought, and pests, the capacity of our forests to absorb carbon is diminishing. Pressures to develop forest lands for urban or agricultural uses also contribute to the decline of forest carbon sequestration. Conservation and sustainable management can help to ensure our forests continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk, and otherwise managing forests to be more resilient in the fact of climate change. The Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate."[23]

Consequently, California is currently in a vicious cycle, wherein due, in part, to Climate Change, it is losing large acres of forests from the wildfires, and less and less acres are available to remove the GHG emissions, thereby contributing to Climate Change. This is part of the reason that the Commission finds that California is currently facing an emergency situation.

It is cognate and germane to our regulation of the utilities to require them to further protect their electric power lines and poles, as discussed herein, in order to prevent their facilities from causing wildfires and to protect their transmission and distribution facilities, which are threatened by wildfires. This is essential, so that the people of the State of California can continue to rely upon the IOUs' critical electric infrastructure, for the provision of safe and reliable electric service. In addition, the utilities can help reduce the risk of wildfires by coordinating with CalFire and engaging in certain forest management efforts. The Commission's Resolution is consistent with our obligations under AB 32 to help ensure that the IOUs under our jurisdiction reduce GHG emissions. We also find it noteworthy that in 2012, the California Legislature passed SB 1122. SB 1122 amended Cal. Pub. Util. Code § 399.20(f) by adding, among other things, a new subpart (2)(A)(iii), which directs the electrical corporations to procure at least 250 megawatts (MW) from developers of new bioenergy projects, including 50 MW from forest biomass facilities (i.e., "bioenergy using byproducts of sustainable forest management"). This subpart further clarifies that these bioenergy projects must be from

[22] Id. at 15.

[23] Id. at 11.

sustainable forest management in "fire threat treatment areas," as designated by CalFire.[24]

**Ratepayer Protections**

The discussion above indicates the exigent need for action on the part of IOUs to ensure public safety and reliable service from the wildfire threats. We are aware of multiple mechanisms that are already available for utilities to recover such costs. For example, in the Fire Safety OIR, we established the Fire Hazard Prevention Memorandum Accounts (FHPMAs) as a mechanism that could be used to seek recovery of costs.[25] Also, IOUs have funding in their General Rate Cases (GRCs), including, specifically authorized vegetation management costs with a one-way balancing account.[26]

To the extent that additional funding is reasonable to address the wildfire threats, beyond such accounts, cost recovery through the Catastrophic Event Memorandum Accounts (CEMAs) may be sought. However, the Commission may analyze such costs to determine if they are truly incremental, and meet the other requirements of CEMA.[27] Consistent with Commission practice, double collection of costs is strictly prohibited. In addition, only costs incurred after the effective date of SED's Acting Director Denise Tyrrell's February 18, 2014 letter, which are not recoverable in another utility account, shall be eligible for CEMA treatment.

Further, to ensure accountability, we shall select independent auditors for the costs associated with this Resolution and to review the IOUs' other accounts to ensure that there is no double recovery and that the costs therein are reasonable. The utilities must keep records to justify the reasonableness of their costs. IOUs shall reimburse the Commission of the audit costs through ratepayer-funding. Of course, if and when an IOU submits its CEMA filing, any interested party may protest the filing.

## COMMENTS

California Public Utilities Code § 311(g)(1) provides that this Resolution be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. California Public Utilities Code § 311(g)(3) provides that this 30-day

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[24] The Commission's implementation of SB 1122 is pending in another proceeding. Our point is that this legislation similarly is requiring the IOUs to coordinate with CalFire in sustainable forest management techniques on the procurement side of their business, as well.

[25] "We will verify and assess the reasonableness of recorded costs in application proceedings." D.14-02-015, *mimeo.*, at 86.

[26] See, e.g., D.13-05-010, *mimeo.*, at 147-156.

[27] D.07-07-041, *mimeo.*, at 3-6.

period may be reduced or waived pursuant to a Commission adopted regulation. In light of Climate Change, which has created a drought, expanded fire seasons and increased the threat of wildfires to the IOUs' critical infrastructure much earlier than in previous years and more significantly throughout the year, the Commission reaffirms that the public necessity supports a reduction on the 30-day comment period. Pursuant to Rule 14.6(c)(9) of the Commission's Rules of Practice and Procedures, notice requirements were therefore shortened for comments on this Draft Resolution, such that one-time comments were due on Monday, June 9, 2014. Comments were submitted by: Liberty Utilities (Liberty), Mussey Grade Road Alliance (MGRA), Pacific Gas & Electric Company (PG&E), PacifiCorp, San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and The Utility Reform Network (TURN).

Most of these comments were generally supportive of this Resolution, though some modifications were urged. Liberty and PacifiCorp both argue against denying recovery for incremental expenses that those utilities incurred in reliance on SED's February 18, 2014 letter, from Acting Director Denise Tyrrell, for the time period between her letter and the June 12, 2014 effective date of this Resolution. The Commission agrees that it was justifiable for utilities to rely on SED's Letter, particularly because Governor Brown had already issued his Emergency Proclamation concerning drought conditions in January of 2014. Such costs would still be subject to review for ratepayer protections as described above.

MGRA generally supports the Commission taking reasonable steps to address climate change and the need to mitigate risks caused by the drought and wildfires. MGRA argues that this Resolution should specify how its orders exceed current regulations and should prevent interference with existing regulations and ongoing proceedings. It is clear that this Resolution does not interfere with existing regulations and ongoing proceedings, but is rather a response to an emergency situation due in part to the drought conditions described by Governor Brown in his Emergency Proclamation. The Resolution requires the utilities to go above and beyond normal operating requirements, and provides for their recovery of incremental costs to address these emergency conditions. This is part of the utilities'requirement that they must keep their facilities safe and reliable based upon their obligations under California Public Utilities Code section 451.

PG&E and SDG&E fully support the prompt adoption of this Draft Resolution. PG&E further supports the necessity of reducing the 30-day comment period so that the Commission may address the ongoing statewide drought conditions. PG&E provides updated facts concerning fires, burn acreage, and other severe conditions caused by the ongoing drought.

PacifiCorp and SCE also support the Resolution, but they express concerns about Ordering Paragraph 2. Sharing resources with CalFire is seen as problematic because it relies, in part, on CalFire's actions, and the requirement to clear access roads is also

potentially problematic due to ownership concerns. Yet, both PacifiCorp and SCE state that they already cooperate with CalFire. We remind the utilities that Ordering Paragraph 2 requires them to take "practicable" steps. Therefore, the expectation is that when such impediments are not present, utilities should be able to promptly comply with the Ordering Paragraph. Should impediments arise, utilities should take practicable steps to comply.

TURN generally supports the Commission taking reasonable steps to address climate change and the need to mitigate risks of wildfires. However, TURN critiques the Draft Resolution for compounding what it views as an "already unduly fractured approach to addressing wildfire-related issues regarding utility facilities." It further critiques SED's diligence in assessing the issues, and offers TURN's view of regulatory accounting mechanisms. TURN would have the Commission designate a single forum for dealing with the issues raised in the Resolution. However, TURN fails to address the fact that the State of California is currently in an emergency situation. Thus, we do not have the time to start a new proceeding to analyze these issues, while Californians are put at risk. TURN also does not fully recognize the ratepayer protections contained within the Resolution. For example, we have prohibited the utilities from double recovery in the various mechanisms, and have provided for independent auditors, chosen by the Commission, to review the costs. TURN, the Office of Ratepayer Advocates, and other intervenors, may challenge the reasonableness of utility actions and incurred costs, if and when utilities seek recovery under CEMA.

## FINDINGS OF FACT

1. On January 17, 2014, Governor Edmund G. Brown, Jr. proclaimed a State of Emergency and directed state officials to take actions to mitigate against conditions that could result from a drought.
2. On February 18, 2014, Denise Tyrrell, Acting Director of the Safety and Enforcement Division (SED) sent a letter to all Investor Owned Electric Utilities (IOUs) that in part directed them to take all practicable measures necessary to reduce the likelihood of fires by their facilities.
3. On March 26, 2014, George Gentry, Executive Officer of the California Board of Forestry and Fire Protection, sent a letter to the Commission in support of the goals of Denise Tyrrell's letter.
4. On May 6, 2014, President Obama issued a press release, entitled: "Fact Sheet: What Climate Change Means for Regions across America and Major Sectors of the Economy," in conjunction with his release of the third U.S. National Climate Assessment (NCA), the most comprehensive scientific assessment ever generated of climate change and its impacts across every region of America and major sectors of the U.S. economy.

5. The purpose of President Obama's May 6, 2014 press release was "*to underscore the need for urgent action to combat threats from climate change, protect American citizens and communities today*, and build a sustainable future … [and to provide the Nation] with the information they need *to cope with changes in climate that are already underway*." (Emphasis added.)

6. The NCA referred to Southwest region of the United States as the hottest and driest region in the United States, which will become significantly drier, resulting in drought and wildfires.

7. On May 14, 2014, Governor Edmund G. Brown, Jr. proclaimed a State of Emergency in San Diego County citing major wildfires which were "difficult to contain" in part due to "extremely dry conditions" and noting that "the fires have damaged and continue to threaten critical infrastructure, including power lines."

8. Statistical data from CalFire indicates an increased number of wildfires from previous years during the first five months of this year.

9. Wildfires threaten the utilities' critical infrastructure, and, therefore the reliability of their vital services.

10. Utility-linked wildfires have had devastating impacts in California.

11. In addition to all of their other devastating impacts, wildfires perpetuate the Climate Changes by destroying numerous acres of forests, which would otherwise reduce the amount of greenhouse gas emissions responsible for much of the Climate Changes.

12. The current drought and recent fires occur as examples establishing the severity of the impacts of Climate Change on Californians.

13. There is an increased chance of large and devastating wildfires occurring this year.

14. There are multiple mechanisms that are already available for utilities to recover costs for mitigation or prevention of wildfires. For example, in the Fire Safety OIR, we established the Fire Hazard Prevention Memorandum Accounts (FHPMAs) as a mechanism that could be used to seek recovery of costs. Also, IOUs have funding in their General Rate Cases (GRCs), including, specifically authorized vegetation management costs with a one-way balancing account.

## CONCLUSIONS OF LAW

1. The state of emergency that has emerged, as demonstrated by the Governor's two Emergency Proclamations and President Obama's statements in conjunction with his release of the third U.S. National Climate Assessment, necessitates immediate action.

2. The Commission may take official notice of official acts of the President of the United States and the Governor of the State of California under Rule 13.9 of our Rules of Practice and Procedure and Cal. Evid. Code § 452(c).

3. The Commission may take official notice of factual matters not reasonably subject to dispute pursuant to Cal. Evid. Code § 452(h). In light of the overwhelming evidence

presented by the scientific community, we find that the effects of greenhouse gas emissions on Climate Change, and the extremely dry conditions, droughts and large number of wildfires, which have resulted from the greenhouse gas emissions and which California is currently experiencing, are factual matters not reasonably subject to dispute.

4. Pursuant to Rule 14.6(c)(9) of the Commission's Rules of Practice and Procedure and California Public Utilities Code § 311(g)(3), the Commission has found that public necessity requires that the Commission reduce the comment period on the Draft Resolution such that one-time comments must be filed by on Monday, June 9, 2014. Notice of this Draft Resolution and the shortening of time for comments to June 9, 2014 was provided by serving the link to the Draft Resolution by e-mail on the official service list in R.08-011-005 (i.e., the Fire Safety OIR) and by web publication pursuant to the Notice for Daily Calendar.

**ORDER:**

1. The Executive Director shall serve this Resolution on the Investor Owned Electric Utilities: PG&E; SCE; SDG&E; PacifiCorp; Liberty Utilities, and Bear Valley Electrical Service.

2. Investor Owned Electric Utilities must take practicable measures necessary to reduce the likelihood of fires associated with their facilities. These measures include: increasing vegetation inspections and removing hazardous, dead and sick trees and other vegetation near the IOUs' electric power lines and poles; sharing resources with the California Department of Forestry and Fire Protection (CalFire) to staff lookouts adjacent to the IOUs' property; and clearing access roads under power lines for fire truck access.

3. Additionally, Investor Owned Electric Utilities should examine and create public-private partnerships during the state of emergency that they find necessary to reduce the likelihood of fires associated with their facilities or to mitigate the impact of fires on their facilities.

4. To the extent that additional funding is reasonable, and not already included or recoverable in the Investor Owned Electric Utilities' accounts, incremental cost recovery through the Catastrophic Event Memorandum Accounts (CEMAs) may be sought by the IOUs after the February 18, 2014 letter from SED. However, the Commission may analyze such costs to determine if they are truly incremental, and meet the other requirements of CEMA. Consistent with Commission practice, double collection of costs is strictly prohibited.

5. The Commission shall select independent auditors for the costs associated with this Resolution and to review the IOUs' other accounts to ensure that there is no double recovery and that the costs therein are reasonable. The utilities must keep records to justify the reasonableness of their costs. IOUs shall reimburse the Commission of the

audit costs through ratepayer-funding. When an IOU submits its CEMA filing, any interested party may protest the filing.

6. Notice requirements were shortened for the purposes of this Resolution due to the public necessity of issuing this Resolution as soon as possible.

7. This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on June 12, 2014; the following Commissioners voting favorably thereon:

/s/ PAUL CLANON
PAUL CLANON
Executive Director

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

# ATTACHMENT 1

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 18, 2014

Mr. Patrick M. Hogan
Vice President Asset Management, Electric Operations
245 Market Street, #1064 (N10A)
San Francisco, CA 94105

Re: Increased Fire Hazards Due to Drought

Mr. Hogan:

On January 17, 2014, Governor Edmund G. Brown Jr. proclaimed a State of Emergency and directed state officials to take all necessary actions to prepare for conditions that could result from the drought. Specifically, the Governor stated:

> We can't make it rain, but we can be much better prepared for the terrible consequences that California's drought now threatens, including dramatically less water for our farms and communities **and increased fires in both urban and rural areas** [Emphasis added]

Due to the increased chance of large and devastating fires in California, I hereby direct you and your company to take all practicable measures necessary to reduce the likelihood of fires started by your facilities. This may include, but is not limited to the following actions:

- Increased inspections in fire threat areas
- Re-prioritization of corrective action items
- Modification to protective schemes

Furthermore, if your company discovers a Safety Hazard, as defined by General Order 95, Rule 18-B and a third party is restricting your company's access to remedy the situation, notify Raymond Fugere of my office immediately, in order that we can work with your company to help resolve the Safety Hazard.

Lastly, the Commission, FERC and CalFire all have established various vegetation requirements and these requirements must be followed at all times. During the State of Emergency the Commission finds it imperative that corrective actions associated with these requirements not be deferred. Notify Mr. Fugere quarterly, of any and all violations of Commission, FERC and/or CalFire vegetation requirements, all notifications must including at least the following:

- Location
- Applicable rule
- Brief description of issue
- Date discovered
- Date corrected
- Actions taken

The above reporting requirements shall stay in effect until the State of Emergency is revoked by the Governor.

It is imperative that your company be aggressive to help reduce the risk of fires during drought conditions. Should you have any questions, please feel free to contact Raymond Fugere at (213) 576-7015, or raymond.fugere@cpuc.ca.gov

Sincerely,

Denise Tyrrell
Acting Director
Safety and Enforcement Division
California Public Utilities Commission

Cc: Edward Randolph, CPUC, Director Energy Division
Elizaveta Malashenko, CPUC, Deputy Director Safety and Enforcement Division
Raymond Fugere, CPUC, Safety and Enforcement Division
Eric Back, PG&E, Director

# ATTACHMENT 2

STATE OF CALIFORNIA—THE NATURAL RESOURCES AGENCY Edmund G. Brown, Jr., *Governor*

**BOARD OF FORESTRY AND FIRE PROTECTION**

P.O. Box 944246
SACRAMENTO, CA 94244-2460
Website: www.bof.fire.ca.gov
(916) 653-8007

March 26, 2014

Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298

President Peavey & Commissioners:

The Board of Forestry & Fire Protection is responsible for wild land fire policy in the State of California. Commensurate with that responsibility, the Board has been evaluating appropriate steps in light of the Governor's Drought Emergency declaration to reduce the extreme fire risk associated with it.

As part of this evaluation, the Board noted that the Commission has sent a letter to utility companies directing them to take all necessary measures to reduce the risk of fire during the drought emergency, including compliance with the rules and regulations of the Board and CAL FIRE.

At its March meeting, the Board unanimously directed me to send a letter that not only endorses the action of the CPUC, but strongly encourages the CPUC to support funding the Utilities at the appropriate levels to conduct this important electric vegetation management work. This may be in the form of pending rate cases, or in supplemental funding as deemed appropriate by the CPUC.

The Utilities can perform significant work that helps to ensure public safety. Given the appropriate resources, a significant public private partnership could be forged. We support timely completion of that work in the face of the extreme conditions presented by this drought.

Sincerely,

George D. Gentry
Executive Officer

# Exhibit 25

Date of Issuance: July 16, 2018

**PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

**SAFETY AND ENFORCEMENT DIVISION** **Resolution ESRB-8**
**Electric Safety and Reliability Branch** **July 12, 2018**

# R E S O L U T I O N

**RESOLUTION EXTENDING DE-ENERGIZATION REASONABLENESS, NOTIFICATION, MITIGATION AND REPORTING REQUIREMENTS IN DECISION 12-04-024 TO ALL ELECTRIC INVESTOR OWNED UTILITIES.**

PROPOSED OUTCOME:

This Resolution extends the de-energization reasonableness, public notification, mitigation and reporting requirements in Decision (D.) 12-04-024 to all electric Investor Owned Utilities (IOUs) and adds new requirements. It also places a requirement on utilities to make all feasible and appropriate attempts to notify customers of a de-energization event prior to performing de-energization.

SAFETY CONSIDERATIONS:

De-energizing electric facilities during dangerous conditions can save lives and property and can prevent wildfires. This resolution provides guidelines that IOUs must follow and strengthens public safety requirements when an IOU decides to de-energize its facilities during dangerous conditions.

ESTIMATED COST: Costs of compliance with the new requirements are unknown.

## SUMMARY

Commission Decision (D.) 12-04-024 established requirements for reasonableness, notification, mitigation and reporting by San Diego Gas & Electric Company (SDG&E) for its de-energization events.

This resolution extends the requirements established in D.12-04-024 to all electric IOUs, requires that the utilities meet with the local communities that may be impacted by a future de-energization event before putting the practice in effect in a particular area, requires feasible and appropriate customer notifications prior to a de-energization event, and requires notification to the Safety and Enforcement Division (SED) as soon as practicable after a decision to de-energize facilities and within 12 hours after the last service is restored.

**BACKGROUND**

California Public Utilities Code (PU Code) Sections 451 and 399.2(a) give electric utilities authority to shut off electric power in order to protect public safety. This authority includes shutting off power for the prevention of fires caused by strong winds.

Application (A.) 08-12-021 filed by SDG&E on December 22, 2008, requested specific authority to shut off power as a fire-prevention measure against severe Santa Ana winds and a review of SDG&E's proactive de-energization measures. SDG&E also requested that such power shut-offs would qualify for an exemption from liability under SDG&E's Tariff Rule 14.

Decision (D.) 12-04-024 issued on April 19, 2012 provided guidance on SDG&E's authority to shut off power under the PU Code and also established factors the Commission may consider in determining whether or not a decision by SDG&E to shut off power was reasonable. The decision ruled that SDG&E has the authority under Public Utilities Code, Sections 451 and 399.2(a) to shut off power in emergency situations when necessary to protect public safety. It also ruled that a decision to shut off power by SDG&E under its statutory authority, including the adequacy of any notice given and any mitigation measures implemented, may be reviewed by the Commission to determine if SDG&E's actions were reasonable. The decision requires SDG&E to take appropriate and feasible steps to provide notice and mitigation to its customers whenever it shuts off power. The decision also requires SDG&E to notify the Commission's Consumer Protection and Safety Division, now the Safety and Enforcement Division (SED), of the shut-off within 12 hours and submit a report to SED with a detailed explanation of its decision to shut off the power.

Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) both currently exercise their authority to shut off power during dangerous fire conditions. However, there are currently no established standards on reasonableness, notification, mitigation and reporting by IOUs other than SDG&E.

**DISCUSSION**

The 2017 California wildfire season was the most destructive wildfire season on record, and saw multiple wildfires burning across California, including five of the 20 most destructive wildland-urban interface fires in the state's history. Devastating fires raged in Santa Rosa, Los Angeles, and Ventura, and the Thomas Fire proved to be the largest wildfire in California history. These fires further demonstrated the fire risk in California. As a result of the fires and critical fire weather conditions, both the President of the United States and the Governor of California issued State of Emergency declarations.

SDG&E exercised its statutory authority under Public Utilities Code Sections 451 and 399.2(a), to de-energize specific circuits in December of 2017. The first group of de-energization events occurred during the period of December 4 through 12, 2017. There were 55 individual circuit de-energization events involving 28 circuits (some circuits had multiple de-energization events) in various eastern San Diego County communities. A total of approximately 14,000 customers were affected.

A second group of de-energization events occurred on December 14 and 15, 2017. There were six individual circuit de-energization events involving three circuits in various eastern San Diego County communities. A total of approximately 650 customers were affected.

In 2017, SCE also used de-energization as a measure to protect its system against fire safety hazards. The de-energization event occurred on December 7, 2017 and affected customers in the community of Idyllwild. Approximately 8,061 total customers were affected in SCE's and nearby Anza Co-Op's service territories. The de-energization event occurred in response to a Red Flag Warning in effect, SCE meteorological forecasting, field-validated extreme high winds and associated fire risks in the area.

According to SCE, during such an event, the company typically attempts to notify customers who could be affected prior to de-energization if timing allows. For the December 7, 2017 event, SCE notified city, county and government officials prior to de-energizing but was not able to notify affected customers prior to the outage occurring. SCE also utilizes other wildfire mitigation practices, such as blocking of distribution reclosers in High Fire Areas, prior to de-energization. According to SCE, de-energization of circuits would be the last line of defense to protect public safety due to extreme fire weather conditions. SCE requires that such an event must be authorized by its activated Incident Management Team.

PG&E reports that prior to 2018, it did not have a policy to de-energize lines as a fire prevention measure. PG&E reported that it did not proactively de-energize lines due to extreme fire weather conditions in 2017. However, in March 2018 PG&E announced that it is developing a program to de-energize lines during periods of extreme fire conditions and has been meeting with local communities to gather feedback.

## I. Current De-Energization Policies Applicable to SDG&E

D.12-04-024 established de-energization policies applicable to SDG&E addressing reporting, reasonableness review and customer notification.

### A. Reporting

Under D.12-04-024, SDG&E is required to provide the following notifications:

- A notification to the Director of SED provided no later than 12 hours after the power shut-off.
- A report to the Director of SED provided no later than 10 business days after the shut-off event ends that includes (i) an explanation of the decision to shut off power; (ii) all factors considered in the decision to shut off power, including wind speed, temperature, humidity, and moisture in the vicinity of the de-energized circuits; (iii) the time, place, and duration of the shut-off event; (iv) the number of affected customers, broken down by residential, medical baseline, commercial/industrial, and other; (v) any wind-related damage to SDG&E's overhead power-line facilities in the areas where power is shut off; (vi) a description of the notice to customers and any other mitigation provided by

SDG&E; and (vii) any other matters that SDG&E believes are relevant to the Commission's assessment of the reasonableness of SDG&E's decision to shut off power.

As other electric IOUs shut off power in a similar manner and in similar situations, such notifications are important to allow safety oversight by SED, and it would be appropriate to have these reporting requirements apply to all electric IOUs' de-energization events.

### B. Reasonableness Review

D.12-04-024 identified several factors that the Commission may consider in assessing whether an SDG&E decision to de-energize "was reasonable and qualifies for an exemption from liability under SDG&E's Electric Tariff Rule 14."[1] These factors are summarized below:

- SDG&E has the burden of demonstrating that its decision to shut off power is necessary to protect public safety.
- SDG&E must rely on other measures, to the extent available, as alternatives to shutting off power.
- SDG&E must reasonably believe that there is an imminent and significant risk that strong winds will topple its power lines onto tinder dry vegetation during periods of extreme fire hazard.
- SDG&E must consider efforts to mitigate the adverse impacts on the customers and communities in areas where it shuts off power. This includes steps to warn and protect its customers whenever it shuts off power.
- Other additional factors, as appropriate, to assess whether the decision to shut off power is reasonable.

As other electric IOUs are developing and/or instituting de-energization plans, it is important that these factors be used to assess the reasonableness of all electric IOU de-energization events in order to ensure that the power shut off is executed only as a last resort and for a good reason. However, we modify the third factor listed above by adding the phrase underlined below:

- [The IOU] must reasonably believe that there is an imminent and significant risk that strong winds will topple its power lines onto tinder dry vegetation <u>or will cause major vegetation-related impacts on its facilities</u> during periods of extreme fire hazard.

### C. Public Outreach, Notification, and Mitigation

D.12-04-024 requires that SDG&E provide notice and mitigation to its customers, to the extent feasible and appropriate, whenever SDG&E shuts off power pursuant to its statutory authority.

[1] D.12-04-024, page 30.

As other electric IOUs are developing and/or instituting de-energization plans, it is important that this requirement for public outreach, notification, and mitigation apply to all electric IOUs in order to ensure that customers are impacted to the least extent necessary. We recognize that it is not practicable to have an absolute requirement that electric IOUs provide advance notification to customers prior to a de-energization event.

## II. Strengthened Requirements Applicable to all Electric IOUs

Recent California experience with wildfires demands that we enhance existing de-energization policy and procedures. In order to ensure that the public and local officials are prepared for power shut off and aware of an IOU de-energization policy, and in order to ensure proper safety oversight by SED, we adopt the following:

1. The guidelines in D.12-04-024, currently applicable to SDG&E only, shall apply to all electric IOUs.
2. The guidelines shall be strengthened as described in the following sections and the strengthened guidelines shall apply to all electric IOUs.

### A. Reporting

IOUs shall submit a report to the Director of SED within 10 business days after each de-energization event, as well as after high-threat events where the IOU provided notifications to local government, agencies, and customers of possible de-energization though no de-energization occurred. Reports to the Director of SED must include at a minimum the following information:

- The local communities' representatives the IOU contacted prior to de-energization, the date on which they were contacted, and whether the areas affected by the de-energization are classified as Zone 1, Tier 2, or Tier 3 as per the definition in General Order 95, Rule 21.2-D.
- If an IOU is not able to provide customers with notice at least 2 hours prior to the de-energization event, the IOU shall provide an explanation in its report.
- The IOU shall summarize the number and nature of complaints received as the result of the de-energization event and include claims that are filed against the IOU because of de-energization.
- The IOU shall provide detailed description of the steps it took to restore power.
- The IOU shall identify the address of each community assistance location during a de-energization event, describe the location (in a building, a trailer, etc.), describe the assistance available at each location, and give the days and hours that it was open.

### B. Reasonableness Review

The reasonableness review discussion in D.12-04-024 and detailed above shall apply to all electric IOUs. At this time, we are not adding additional requirements and, while we recognize that this issue along with financial liability are important ongoing discussions, this resolution is not the venue for that discussion.

### C. Public Outreach, Notification, and Mitigation

Increased coordination, communication and public education can be effective measures to increase public safety and minimize adverse impact from de-energization.

- The IOU shall notify the Director of SED, as soon as practicable, once it decides to de-energize its facilities. If the notification was not prior to the de-energization event, the IOU shall explain why a pre-event notification was not possible. The notification shall include the area affected, an estimate of the number of customers affected, and an estimated restoration time. The IOU shall also notify the Director of SED of full restoration within 12 hours from the time the last service is restored.
- Within 90 days of the effective date of this resolution, each IOU shall convene De-Energization Informational Workshops with representatives of entities that may be affected by a de-energization event, including but not limited to: state agencies, tribal governments, local agencies and representatives from local communities. Workshops should be inclusive of, but not limited to, representatives of customers who are low-income, have limited English, have disabilities, or are elderly. The purpose of these workshops is to explain, and receive feedback on, the IOU's de-energization policies and procedures. The workshops should be supplemented by focused working sessions, upon request by specific groups such as communications providers or Community Choice Aggregators that might have notification needs different than those of the general public.
- Within 30 days of the effective date of this resolution, each IOU shall submit a report to the Director of SED outlining its public outreach, notification, and mitigation plan. The plan must include at a minimum, the following information:
    - Names of communities that will be invited to De-Energization Informational Workshops.
    - Names of state agencies and tribal governments that the IOU will coordinate with in developing its de-energization plan and will invite to De-Energization Informational Workshops.
    - Names of local agencies the IOU will coordinate with in developing its de-energization plan and will invite to De-Energization Informational Workshops.
    - Proposed communication methods for publicizing and convening the De-Energization Informational Workshops.
    - Details regarding its plans for notification in advance of, and during, a de-energization event, and its plans for mitigation when de-energization occurs.
- The IOU shall ensure that de-energization policies and procedures are well-communicated and made publicly available, including the following:
    - Make available and post a summary of de-energization policies and procedures on its website.
    - Meet with representatives from local communities that may be affected by

    de-energization events, before putting the practice in effect in a particular area.
  - Provide its de-energization and restoration policy in full, and in summary form, to the affected community officials before de-energizing its circuits.
  - Discuss the details of any potential shut-off and mitigation measures that the communities should consider putting in place, including information about any assistance that the IOU may be able to provide during events.
- In anticipation of a specific de-energization event, the IOU shall:
  - Notify customers of planned de-energization as soon as practicable before the event.
  - As practicable and operationally feasible, notify and communicate with representatives from the fire departments, first responders, local communities, government, communications providers, and Community Choice Aggregators that may be affected by the de-energization event.
  - Discuss with local government and community representatives the details of any potential shut-off and mitigation measures the IOU can provide to lessen the negative impacts of the power outage (e.g., cooling centers).
  - Ensure that critical facilities such as hospitals, emergency centers, fire departments, and water plants are aware of the planned de-energization event.
- The IOU shall retain documentation of community meetings and information provided in electronic form, and make that information available to SED upon request. The information shall be retained for a minimum of one year after the de-energization event or five years after the community meetings, whichever comes first.
- After the de-energization event, IOUs shall assist critical facility customers to evaluate their needs for backup power and determine whether additional equipment is needed. To address public safety impacts of a de-energization event, the IOU may provide generators to critical facilities that are not well prepared for a power shut off.
- The IOU shall retain records of customer notifications and make that information available to SED upon request. The information shall be retained for a minimum of one year after the de-energization event.

## COMMENTS ON DRAFT RESOLUTION

PU Code Section 311(g)(1) provides that a resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding or in other specified situations.

The draft resolution was mailed to parties for comment on May 30, 2018, and was noticed on the Commission's Daily Calendar on June 8, 2018. The 30-day comment period for the draft resolution was neither waived nor reduced. Parties submitted comments by June 28, 2018, and reply comments by July 6, 2018.

Based on parties' comments, several modifications were made to the draft resolution, including the following:

- One of the factors specified in D.12-04-024 for consideration during reasonableness reviews was expanded for use when applied to all IOUs.
- The requirements for reporting events that do not eventually trigger de-energization were clarified.
- The full restoration reporting period to the SED was increased from 30 minutes to 12 hours.
- The period for convening De-Energization Informational Workshops was increased from 60 days to 90 days.
- The guidance for meeting with local communities was made a general requirement, rather than tied to specific de-energization events.
- Low-income, limited English, and disability communities were added to the list of parties to include in the De-Energization Informational Workshops.
- Communications providers were added to the list of representatives to be notified in anticipation of a de-energization event.
- The requirement to provide generators and/or batteries to critical facilities was removed since most critical facilities are required to have their own back-up power resources.

Also in response to comments by the parties, we clarify that the requirements adopted in this resolution are not in conflict with IOU authority to de-energize power lines to ensure public safety provided under the PU Code. We expect an IOU to use its best judgment on a case-by-case basis to determine whether de-energization is needed for public safety. We hold this expectation even if an IOU has not complied fully with each of the requirements in this resolution, for example, if a need for de-energization arises before an IOU has meet with the impacted local communities. If an IOU did not fulfill one or more of the requirements in this resolution prior to a de-energization, the IOU shall identify the missed requirement(s) and provide an explanation in its report submitted to the Director of SED after the de-energization event.

## FINDINGS

1. Under PU Code Sections 451 and 399.2(a), electric IOUs have the authority to shut off power in order to protect public safety.
2. The decision to de-energize electric facilities for public safety is complex and dependent on many factors including and not limited to fuel moisture; aerial and ground firefighting capabilities; active fires that indicate fire conditions; situational awareness provided by fire agencies, the National Weather Service and the United States Forest Service; and local meteorological conditions of humidity and winds.
3. The decision to shut off power may be reviewed by the Commission pursuant to its broad jurisdiction over public safety and utility operations.

4. The requirements for reporting, public outreach, notification, mitigation and reasonableness review in D.12-04-024 are effective, but are only applicable to SDG&E.
5. All electric IOUs may face similar safety situations requiring power shut-off in emergencies and de-energization events in their service territory.
6. De-energization of electric facilities could save lives, protect property, and prevent fires.
7. The measures in D.12-04-024 should be strengthened to further ensure that the public and local officials are prepared for de-energization events and to ensure the proper safety oversight by the Commission's Safety and Enforcement Division.

**THEREFORE, IT IS ORDERED THAT:**

1. All electric IOUs shall take appropriate and feasible steps to provide notice and mitigation to their customers in accordance with the guidelines in D.12-04-024 whenever they shut off power pursuant to their statutory authority.
2. All electric IOUs shall follow the notification requirements to SED established in D.12-04-024.
3. All electric IOUs shall comply with the additional guidelines stated in the section of this resolution titled "**Strengthened Requirements Applicable to all Electric IOUs.**"

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on July 12, 2018; the following Commissioners voting favorably thereon:

/s/ *ALICE STEBBINS*
ALICE STEBBINS
Executive Director

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

# Exhibit 26

STATE OF CALIFORNIA

# RULES

FOR

# Overhead Electric Line Construction

Prescribed by the

PUBLIC UTILITIES COMMISSION

OF THE

**STATE OF CALIFORNIA**

GENERAL ORDER No. 95

**January 2016**

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**(1) Definition of major accidents and failures:**

**(a)** Incidents associated with utility facilities which cause property damage estimated at or about the time of the incident to be more than $50,000.

**(b)** Incidents resulting from electrical contact which cause personal injury which require hospitalization overnight, or result in death.

**EXCEPTION:** Does not apply to motor vehicle caused incidents.

Note: Added January 13, 2005 by Decision No. 0501030.

## 18 Reporting and Resolution of Safety Hazards Discovered by Utilities

For purposes of this rule, "Safety Hazard" means a condition that poses a significant threat to human life or property.

"Southern California" is defined as the following: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties.

"Extreme and Very High Fire Threat Zones" are defined on the Fire and Resource Assessment Program (FRAP) Map prepared by the California Department of Forestry and Fire Protection or the modified FRAP Map prepared by San Diego Gas & Electric Company (SDG&E) and adopted by Decision 12-02-032 in Phase 2 of Rulemaking 08-11-005. All entities subject to Rule 18 shall use the FRAP Map to implement Rule 18, except that SDG&E may use its modified FRAP Map to implement Rule 18.

### A Resolution of Safety Hazards and General Order 95 Nonconformances

(1) (a) Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 nonconformances posed by its facilities.

(b) Upon completion of the corrective action, the company's records shall show, with sufficient detail, the nature of the work, the date, and the identity of persons performing the work. These records shall be preserved by the company for at least ten (10) years and shall be made available to Commission staff upon 30 days notice.

(c) Where a communications company's or an electric utility' actions result in GO nonconformances for another entity, that entity's remedial action will be to transmit a single documented notice of identified nonconformances to the communications company or electric utility for compliance.

(2) (a) All companies shall establish an auditable maintenance program for their facilities and lines. All companies must include a timeline for corrective actions to be taken following the identification of a Safety Hazard or nonconformances with General Order 95 on the company's facilities. The auditable maintenance program shall prioritize corrective actions consistent with the priority levels set forth below and based on the following factors, as appropriate:

- Safety and reliability as specified in the priority levels below;
- Type of facility or equipment;
- Location, including whether the Safety Hazard or nonconformance is located in an Extreme or Very High Fire Threat Zone in Southern California;
- Accessibility;
- Climate;
- Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public.

There shall be 3 priority levels.

(i) Level 1:
  - Immediate safety and/or reliability risk with high probability for significant impact.
  - Take action immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

(ii) Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority). Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed: (1) 12 months for nonconformances that compromise worker safety, (2) 12 months for nonconformances that create a fire risk and are located in an Extreme or Very High Fire Threat Zone in Southern California, and (3) 59 months for all other Level 2 nonconformances.

(iii) Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) as appropriate.
-

(b) Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)
-

(3) Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18A shall continue to follow their General Order 165 programs.

## B. Notification of Safety Hazards

If a company, while performing inspections of its facilities, discovers a safety hazard(s) on or near a communications facility or electric facility involving another company, the inspecting company shall notify the other company and/or facility owner of such safety hazard(s) no later than 10 business days after the discovery. To the extent the inspecting company cannot determine the facility owner/operator, it shall contact the pole owner(s), who shall be responsible for promptly notifying the company owning/operating the facility with the safety hazard(s), normally not to exceed five business days after being notified of the safety hazard. The notification shall be documented and such documentation must be preserved by all parties for at least ten years.

Note: Each pole owner must be able to determine all other pole owners on poles it owns. Each pole owner must be able to determine all authorized entities that attach equipment on its portion of a pole.

Note: Added August 20, 2009 by Decision No. 09-08-029. Revised January 12, 2012 by Decision No. 1201032.

## 19 Cooperation with Commission Staff; Preservation of Evidence Related to Incidents Applicability of Rules

Each utility shall provide full cooperation to Commission staff in an investigation into any major accident (as defined in Rule 17) or any reportable incident (as defined in CPUC Resolution E-4184), regardless of pending litigation or other investigations, including those which may be related to a Commission staff investigation. Once the scene of the incident has been made safe and service has been restored, each utility shall provide Commission staff upon request immediate access to:

- Any factual or physical evidence under the utility or utility agent's physical control, custody, or possession related to the incident;
- The name and contact information of any known percipient witness;
- Any employee percipient witness under the utility's control;
- The name and contact information of any person or entity that has taken possession of any physical evidence removed from the site of the incident;
- Any and all documents under the utility's control that are related to the incident and are not subject to the attorney-client privilege or attorney work product doctrine.

Any and all documents or evidence collected as part of the utility's own investigation related to the incident shall be preserved for at least five years. The Commission's statutory authorization under Cal. Pub. Util. Code §§ 313, 314, 314.5, 315, 581, 582, 584, 701, 702, 771, 1794, 1795, 8037 and 8056 to obtain information from utilities, which relate to the incidents described above, is delegated to Commission staff.

Note: Added August 20, 2009 by Decision No. 09-08-029

### F. Energized Conductor (Wire or Cable)

All energized conductor (wire or cable) shall be covered with an insulation suitable for the voltage involved (See Rule 20.9–G).

### G. Guying

Where mechanical loads imposed on poles or structures exceed safety factors as specified in Rule 44, or at the request of the granting authority, additional strength shall be provided by the use of guys or other suitable construction. When guying is required, refer to Rules 56 and 86 for applicable requirements.

Note: Revised November 6,1992 by Resolution No. SU–15.

## 35 Vegetation Management

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances, the minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions shall be maintained. (Also see Appendix E for tree trimming guidelines.) These requirements apply to all overhead electrical supply and communication facilities that are covered by this General Order, including facilities on lands owned and maintained by California state and local agencies.

When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that dead, rotten or diseased trees or dead, rotten or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of supply or communication lines, said trees or portions thereof should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that its circuit energized at 750 volts or less shows strain or evidences abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension, rearranging or replacing the conductor, pruning the vegetation, or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the vegetation and conductor. Scuffing or polishing of the insulation or covering is not considered abrasion. Strain on a conductor is present when vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors, in and of itself, does not constitute a nonconformance with the rule.

**EXCEPTIONS:**

**1.** Rule 35 requirements do not apply to conductors, or aerial cable that complies with Rule 57.4-C, energized at less than 60,000 volts, where trimming or removal is not practicable and the conductor is separated from the tree with suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.

**2.** Rule 35 requirements do not apply where the utility has made a "good faith" effort to obtain permission to trim or remove vegetation but permission was refused or unobtainable. A "good faith" effort shall consist of current documentation of a minimum of an attempted personal contact and a written communication, including documentation of mailing or delivery. However, this does not preclude other action or actions from demonstrating "good faith". If permission to trim or remove vegetation is unobtainable and requirements of exception 2 are met, the utility is not compelled to comply with the requirements of exception 1.

**3.** The Commission recognizes that unusual circumstances beyond the control of the utility may result in nonconformance with the rules. In such cases, the utility may be directed by the Commission to take prompt remedial action to come into conformance, whether or not the nonconformance gives rise to penalties or is alleged to fall within permitted exceptions or phase–in requirements.

Note: Revised November 6,1992 by Resolution No. SU–15, September 20, 1996 by Decision No. 96–09–097, January 23, 1997 by Decision No. 97–01–044 and January 13, 2005 by Decision No. 0501030..

**4.** Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six–inch minimum clearance under reasonably foreseeable local wind and weather conditions. The utility shall bear the risk of determining whether this exemption applies, and the Commission shall have final authority to determine whether the exemption applies in any specific instance, and to order that corrective action be taken in accordance with this rule, if it determines that the exemption does not apply.

Note: Added October 22, 1997 by Decision No. 97–10–056. Revised August 20, 2009 by Decision No. 09-08-029 and January 12, 2012 by Decision No. 1201032

## 36 Pole Clearances from Railroad Tracks

Poles or other supporting structures which are set in proximity to railroad tracks shall be so located that the clearance requirements of General Order 26–D are met. The clearance requirements of General Order 26–D, applicable to pole line construction, are contained in Appendix E.

Note: Revised February 1, 1948 by Supplement No. 1 (Decision No. 41134, Case No. 4324).

## 37 Minimum Clearances of Wires above Railroads, Thoroughfares, Buildings, Etc.

Clearances between overhead conductors, guys, messengers or trolley span wires and tops of rails, surfaces of thoroughfares or other generally accessible areas across, along or above which any of the former pass; also the clearances between conductors, guys, messengers or trolley span wires and buildings, poles, structures, or other objects, shall not be less than those set forth in Table 1, at a temperature of 60° F. and no wind.

The clearances specified in Table 1, Case 1, Columns A, B, D, E and F, shall in no case be reduced more than 5% below the tabular values because of temperature and loading as specified in Rule 43, or other conditions. The clearances specified in Table 1, Cases 2 to 6 inclusive, shall in no case be reduced more than 10% below the tabular values because of temperature and loading as specified in Rule 43, or other conditions.

The clearance specified in Table 1, Case 1, Column C (22.5 feet), shall in no case be reduced below the tabular value because of temperature and loading as specified in Rule 43.

The clearances specified in Table 1, Cases 11, 12 and 13, shall in no case be reduced below the tabular values because of temperatures and loading as specified in Rule 43.

Where supply conductors are supported by suspension insulators at crossings over railroads which transport freight cars, the initial clearances shall be sufficient to prevent reduction to clearances less than 95% of the clearances specified in Table 1, Case 1, through the breaking of a conductor in either of the adjoining spans.

Where conductors, dead ends, and metal pins are concerned in any clearance specified in these rules, all clearances of less than 5 inches shall be applicable from surface of conductors (not including tie wires), dead ends, and metal pins, except clearances between surface of crossarm and conductors supported on pins and insulators (referred to in Table 1, Case 9) in which case the minimum clearance specified shall apply between center line of conductor and surface of crossarm or other line structure on which the conductor is supported.

All clearances of 5 inches or more shall be applicable from the center lines of conductors concerned.

When measuring the minimum allowable vertical conductor clearances in a span, the minimum clearance applies to the specific location under the span being measured and not for the entire span.

Note: Modified January 8, 1980 by Decision No. 91186, March 9, 1988 by Resolution E–3076; and November 6, 1992 by Resolution SU–15, September 20, 1996 by Decision 96–09–097, January 23, 1997 by Decision 97–01–044 and January 13, 2005 by Decision No. 0501030.

**Table 1: Basic Minimum Allowable Vertical Clearance of Wires above Railroads, Thoroughfares, Ground or Water Surfaces; Also Clearances from Poles, Buildings, Structures or Other Objects (nn) (Letter References Denote Modifications of Minimum Clearances as Referred to in Notes Following This Table)**

| Case No. | Nature of Clearance | Wire or Conductor Concerned | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | A<br>Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers | B<br>Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts | C<br>Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts | D<br>Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8 | E<br>Supply Conductors and Supply Cables, 750 - 22,500 Volts | F<br>Supply Conductors and Supply Cables, 22.5 - 300 kV | G<br>Supply Conductors and Supply Cables, 300 - 550 kV (mm) |
| 1 | Crossing above tracks of railroads which transport or propose to transport freight cars (maximum height 15 feet, 6 inches) where not operated by overhead contact wires. (a) (b) (c) (d) | 25 Feet | 25 Feet | 22.5 Feet | 25 Feet | 28 Feet | 34 Feet | 34 Feet (kk) |
| 2 | Crossing or paralleling above tracks of railroads operated by overhead trolleys. (b) (c) (d) | 26 Feet (e) | 26 Feet (e) (f) (g) | 22.5 Feet (h) (i) (eee) | 27 Feet (e) (g) | 30 Feet (g) | 34 Feet (g) | 34 Feet (g) (kk) |
| 3 | Crossing or along thoroughfares in urban districts or crossing thoroughfares in rural districts. (c) (d) | 18 Feet (j) (k) (ii) | 18 Feet (j) (l) (m) (ii) (kkk) | 19 Feet (hh) (eee) | 20 Feet (ii) | 25 Feet (o) (ii) | 30 Feet (o) (ii) | 30 Feet (o) (ii) (kk) |
| 4 | Above ground along thoroughfares in rural districts or across other areas capable of being traversed by vehicles or agricultural equipment. | 15 Feet (k) | 15 Feet (m) (n) (p) | 19 Feet (eee) | 19 Feet | 25 Feet (o) | 30 Feet (o) (p) | 30 Feet (o) (kk) |
| 5 | Above ground in areas accessible to pedestrians only | 8 Feet | 10 Feet (m) (q) | 19 Feet (eee) | 12 Feet | 17 Feet | 25 Feet (o) | 25 Feet (o) (kk) |
| 6 | Vertical clearance above walkable surfaces on buildings, (except generating plants or substations) bridges or other structures which do not ordinarily support conductors, whether attached or unattached. | 8 Feet (r) | 8 Feet (r) | 8 Feet | 8 Feet | 12 Feet | 12 Feet | 20 Feet (ll) |
| 6a | Vertical clearance above non–walkable surfaces on buildings, (except generating plants or substations) bridges or other structures, which do not ordinarily support conductors, whether attached or unattached | 2 Feet | 8 Feet (yy) | 8 Feet | 8 Feet (zz) | 8 Feet | 8 Feet | 20 Feet |
| 7 | Horizontal clearance of conductor at rest from buildings (except generating plants and substations), bridges or other structures (upon which men may work) where such conductor is not attached thereto (s) (t) | - | 3 Feet (u) | 3 Feet | 3 Feet (u) (v) | 6 Feet (v) | 6 Feet (v) | 15 Feet (v) |
| 8 | Distance of conductor from center line of pole, whether attached or unattached (w) (x) (y) | - | 15 inches (s) (aa) | 15 inches (aa) (bb) (cc) | 15 inches (o) (aa) (dd) | 15 or 18 inches (o) (dd) (ee) (jj) | 18 inches (dd) (ee) | Not Applicable |
| 9 | Distance of conductor from surface of pole, crossarm or other overhead line structure upon which it is supported, providing<br>it complies with case 8 above (x) | - | 3 inches (aa) (ff) | 3 inches (aa) (cc) (gg) | 3 inches (aa) (dd) (gg) | 3 inches (dd) (gg) (jj) | 1/4 Pin Spacing Shown in Table 2 Case 15 (dd) | 1/2 Pin Spacing Shown in Table 2 Case 15 (dd) |

**Table 1 (Continued)**

| Case No. | Nature of Clearance | Wire or Conductor Concerned | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | A<br>Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers | B<br>Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts | C<br>Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts | D<br>Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8 | E<br>Supply Conductors and Supply Cables, 750 - 22,500 Volts | F<br>Supply Conductors and Supply Cables, 22.5 - 300 kV | G<br>Supply Conductors and Supply Cables, 300 - 550 kV (mm) |
| 10 | Radial centerline clearance of conductor or cable (unattached) from non-climbable street lighting or traffic signal poles or standards, including mastarms, brackets and lighting fixtures, and from antennas that are not part of the overhead line system. | - | 1 Foot (u) (rr) (ss) | 15 inches (bb) (cc) | 3 Feet (oo) | 6 Feet (pp) | 10 Feet (qq) | 10 Feet (ll) |
| 11 | Water areas not suitable for sailboating (tt) (uu) (ww) (xx) | 15 Feet | 15 Feet | - | 15 Feet | 17 Feet | 25 Feet | 25 Feet (kk) |
| 12 | Water areas suitable for sailboating, surface area of: (tt) (vv) (ww) (xx)<br>(A) Less than 20 acres<br>(B) 20 to 200 acres<br>(C) Over 200 to 2,000 acres<br>(D) Over 2,000 acres | <br><br>18 Feet<br>26 Feet<br>32 Feet<br>38 Feet | <br><br>18 Feet<br>26 Feet<br>32 Feet<br>38 Feet | <br><br>-<br>-<br>- | <br><br>18 Feet<br>26 Feet<br>32 Feet<br>38 Feet | <br><br>20 Feet<br>28 Feet<br>34 Feet<br>40 Feet | <br><br>27 Feet<br>35 Feet<br>41 Feet<br>47 Feet | <br><br>27 Feet (kk)<br>35 Feet (kk)<br>41 Feet (kk)<br>47 Feet (kk) |
| 13 | Radial clearance of bare line conductors from tree branches or foliage (aaa) (ddd) | - | - | 18 inches (bbb) | - | 18 inches (bbb) | 1/4 pin spacing shown in table 2, Case 15 (bbb) (ccc) | 1/2 pin spacing shown in table 2, Case 15 |
| 14 | Radial clearance of bare line conductors from vegetation in Extreme and VeryHigh Fire Threat Zones in Southern California (aaa) (ddd) (hhh)(jjj) | | | 18 inches (bbb) | | 48 inches (bbb) (iii) | 48 inches (fff) | 120 inches (ggg) |

**References to Rules Modifying Minimum Clearances in Table 1** Rule

(a) Shall not be reduced more than 5% because of temperature or loading 37
   1 Supply lines 54.4–B1
   2 Communication lines 84.4–B1
(b) Shall be increased for supply conductors on suspension insulators, under certain conditions 37
(c) Special clearances are provided for traffic signal equipment 58.4–C
(d) Special clearances are provided for street lighting equipment 58.5–B
(e) Based on trolley pole throw of 26 feet. may be reduced where suitably protected 56.4–B2
   1 Supply guys 56.4–B2
   2 Supply cables and messengers 57.4–B2
   3 Communication guys 86.4–B2
   4 Communication cables and messengers 87.4–B2
(f) May be reduced depending on height of trolley contact conductors
   1 Supply service drops 54.8–C5
   2 Communication service drops 84.8–D5
(g) May be reduced and shall be increased depending on trolley throw
   1 Supply conductors (except service drops) 54.4–B2
   2 Communication conductors (except service drops) 84.4–B2
(h) May be decreased where freight cars are not transported.
   1. Trolley contact and feeder conductors. 74.4-B1

Rule

   2. Trolley span wires 77.4-A
(i) May be reduced for trolley contact and span wires in subways, tunnels, under bridges and in fenced areas
   1 Trolley contact conductors 74.4–E
   2 Trolley span wires 77.4–B
(j) May be reduced at crossings over private thoroughfares and entrances to private property and over private property
   1 Supply service drops 54.8–B2
   2 Supply guys 56.4–A
   3 Communication service drops 84.8–C2
   4 Communication guys 86.4–A
(k) May be reduced along thoroughfares where not normally accessible to vehicles
   1 Supply guys 56.4–A1
   2 Communication guys 86.4–A1
(l) May be reduced where within 12 feet of curb line of public thoroughfares
   1 Supply service drops 54.8–B1
   2 Communication service drops 84.8–C1
(m) May be reduced for railway signal cables under special conditions 84.4–A4

**References to Rules Modifying Minimum Clearances in Table 1**

| | | | Rule |
|---|---|---|---|
| (n) | May be reduced in rural districts | | |
| | 1 | Intentionally left blank | |
| | 2 | Intentionally left blank | |
| | 3 | Communication conductors along roads | 84.4–A2 |
| (o) | May be reduced for transformer, regulator or capacitor leads | | |
| | 1 | Transformer leads | 58.1–B |
| | 2 | Regulator or capacitor leads | 58.1–B |
| (p) | May be reduced across arid or mountainous areas | | |
| | 1 | Supply conductors of more than 22,500 volts | 54.4–A1 |
| | 2 | Communications conductors | 84.4–A1 |
| (q) | Shall be increased or may be reduced under special conditions | | |
| | 1 | Supply service drops | 54.8–B3 |
| | 2 | Intentionally left blank | |
| | 3 | Communications conductors | 84.4–A3 |
| | 4 | Increased for communication service drops on industrial or commercial premises | 84.8–C3a |
| | 5 | Communication service drops on residential premises | 84.8–C3b |
| (r) | May be reduced above roofs of buildings under special conditions | | |
| | 1 | Supply overhead guys | 56.4–G |
| | 2 | Supply service drops | 54.8–B4 |
| | 3 | Communication overhead guys | 86.4–F |
| | 4 | Communication conductors and cables | 84.4–E |
| | 5 | Communication service drops | 84.8–C4 |
| (s) | Also applies at fire escapes, etc. | | |
| | 1 | Supply conductors | 54.4–H1 |
| | 2 | Vertical clearances | 54.8B4a |
| | 3 | Horizontal clearance | 54.8–B4b |
| | 4 | Communication conductors | 84.4–E |
| (t) | Special clearances where attached to buildings, bridges or other structures | | |
| | 1 | Supply conductors of 750 - 22,500 volts | 54.4–H2 |
| | 2 | Trolley contact conductors | 74.4–E |
| | 3 | Communication conductors | 84.4–F |
| (u) | Reduced clearances permitted under special conditions | | |
| | 1 | Supply service drops on industrial or commercial premises | 54.8–B4a |
| | 2 | Supply cables, grounded | 57.4–G |
| | 3 | Communication cables beside buildings, etc. | 84.4–E |
| | 4 | Communication conductors under bridges, etc. | 84.4–F |
| | 5 | Communication service drops | 84.8–C4 |
| | 6 | Communication cables passing nonclimbable street light poles, etc. | 84.4–D4a |
| (v) | May be reduced under special conditions | | |
| | 1 | Supply conductors of 750 - 7,500 volts | 54.4–H1 |
| | 2 | Supply transformer lead and bus wires, where guarded | 58.1 |
| (w) | May be reduced at angles in lines and transposition points | | |
| | 1 | Supply conductors | 54.4–D1 |
| | 2 | Communication conductors | 84.4–D5 |
| (x) | May be reduced for suitably protected lateral or vertical runs | | |
| | 1 | Supply bond wires | 53.4 |
| | 2 | Supply ground wires | 54.6–B |
| | 3 | Supply lateral conductors | 54.6–C |
| | 4 | Supply vertical runs | 54.6–D |
| | 5 | Supply risers | 54.6–E |
| | 6 | Communication ground wires | 84.6–B |
| | 7 | Communication lateral conductors | 84.6–C |
| | 8 | Communication vertical runs | 84.6–D |
| | 9 | Communication risers | 84.6–E |
| (y) | Increased clearances required for certain conductors | | |
| | 1 | Unattached conductors on colinear and crossing lines | 32.3 |
| | 2 | Unattached supply conductors | 54.4–D3 |
| | 3 | Supply service drops on clearance crossarms | 54.8–C2 |
| | 4 | Supply service drops on pole top extensions | 54.8–C3 |
| | 5 | Unattached supply service drops | 54.8–D |
| | 6 | Communication lines, colinear, conflicting or crossing | 84.4–D3 |
| | 7 | Communication conductors passing supply poles and unattached thereto | 84.4–D4 |
| | 8 | Communication service drops on clearance crossarms | 84.8–D2 |
| | 9 | Communication service drops on pole top extensions | 84.8–D3 |
| | 10 | Unattached communication service drops | 84.8–E |
| (z) | Special provisions for police and fire alarm conductors require increased clearances | | 92.2 |
| (aa) | May be reduced under special provisions | | |
| | 1 | Supply conductors of 0 - 750 volts in rack configuration | 54.4–D5 |
| | 2 | Service supply drops from racks | 54.8–F |
| | 3 | Supply cables and messengers attached to poles | 57.4–F |
| | 4 | Communication conductors on communication poles | 84.4–D |
| | 5 | Communication conductors on crossarms | 84.4–D1 |
| | 6 | Communication conductors attached to poles | 84.4–D2 |
| | 7 | Communication service drops attached to poles | 84.8–B |
| | 8 | Communication cables and messengers | 87.4–D |
| | 9 | Supply or communication cables and messengers on jointly used poles | 92.1–B |
| | 10 | Communication open wire on jointly used poles | 92.1–C |
| | 11 | Multiconductor cable with bare neutral | 54.10–B1 |
| (bb) | May be reduced for class t conductors of not more than 750 volts and of the same potential and polarity | | 74.4–D |
| (cc) | Not applicable to trolley span wires | | 77.4–E |
| (dd) | Special clearances for pole–top and deadend construction | | |
| | 1 | Conductors deadended in vertical configuration on poles | 54.4–C4 |
| | 2 | Conductors deadended in horizontal configuration | 54.4–D8 |
| (ee) | Clearance requirements for certain voltage classifications | | 54.4–D2 |
| (ff) | Not applicable to communication conductors | | 84.4–D |
| (gg) | Clearance from crossarms may be reduced for certain conductors | | |
| | 1 | Suitable insulated leads to protect runs | 54.4–E |
| | 2 | Leads of 0 - 5,000 volts to equipment | 54.4–E |
| | 3 | Leads of 0 - 5,000 volts to cutouts or switches | 58.3–A2 |
| (hh) | Reduced clearance permitted from temporary fixtures and lighting circuits 0 - 300 volts | | 78.3–A1 |
| (ii) | Special Clearances Required Above Public and Private Swimming Pools | | |
| | 1 | Supply line conductors | 54.4–A3 |
| | 2 | Supply service drops | 54.8–B5 |
| | 3 | Communication line conductors | 84.4–A5 |
| | 4 | Communication service drops | 84.8–C5 |
| | 5 | Supply guys, span wires | 56.4–A3 |
| | 6 | Communication guys | 86.4–A3 |
| (jj) | May be decreased in partial underground distribution | | 54.4–D2 |

**References to Rules Modifying Minimum Clearances in Table 1** Rule

(kk) Shall be increased by 0.025 feet per kV in excess of 300 kV
(ll) Shall be increased by 0.04 feet per KV in excess of 300 kV
(mm) Proposed clearances to be submitted to the cpuc prior to construction for circuits in excess of 550 kV.
(nn) Voltage shown in the table shall mean line–to–ground voltage for direct current (DC) systems
(oo) May Be reduced for grounded or multi–conductor cables
 1 Grounded cables 57.4–H
 2 Multi–Conductor cables 54.10–B2
(pp) May be reduced to 4 feet for voltages below 7,500 volts 54.4–D3
(qq) May be reduced to 6 feet for voltages below 75 kV
(rr) May be reduced for supply service drops 54.8–D1
(ss) May be reduced for communications service drops 84.8–E1
(tt) Where a federal agency or surrogate thereof has issued a crossing permit, clearances of that permit shall govern.
(uu) Or where sailboating is prohibited and where other boating activities are allowed
(vv) Clearance above contiguous ground shall be 5 feet greater than in cases 11 or 12 for the type of water area served for boat launch facilities and for area contiguous thereto, that are posted, designated or specifically prepared for rigging of sailboats or other watercraft.
(ww) For controlled impoundments, the surface areas and corresponding clearances shall be based upon the high water level. for other waters, the surface area shall be that enclosed by its annual flood level. the clearance over rivers, streams and canals shall be based upon the largest surface areas of any one–mile long segment which includes the crossing. The clearance over a canal, river or stream normally used to provide access for sailboats to a larger body of water shall be the same as that required for the larger body of water.
(xx) Water areas are lakes, ponds, reservoirs, tidal waters, rivers, streams and canals without surface obstructions.
(yy) May be reduced over non–walkable structures 54.8 (Table 10)
(zz) May be reduced to 2 feet for conductors insulated in accordance with 20.9–G
(aaa) Special requirements for communication and supply circuits energized at 0 - 750 volts 35
(bbb) May be reduced for conductor of less than 60,000 volts when protected from abrasion and grounding by contact with tree 35
(ccc) For 22.5 kV to 105 kV, minimum clearance shall be 18 inches.
(ddd) Clearances in this case shall be maintained for normal annual weather variations, rather than at 60 degrees, no wind.

Rule

(eee) May be reduced to 18 feet if the voltage does not exceed 1000 volts and the clearance is not reduced to more than 5% below the reduced value of 18 feet because of temperature and loading as specified in Rules 37 and 43.
(fff) Clearances in this case shall be increased for conductors operating above 72 kV, to the following:
 1 Conductors operating between 72kV and a 110 kV shall maintain a 72 inch clearance
 2 Conductors operating above 110 kV shall maintain a 120 inch clearance
(ggg) Shall be increased by 0.40 inch per kV in excess of 500 kV
(hhh) Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries for purposes of this rule. The boundaries of the map are to be broadly construed, and utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map. Southern California shall be defined as the following: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties.
(iii) May be reduced to 18 inches for conductors operating less than 2.4 kV.
(jjj) Clearances in this case shall not apply to orchards of fruit, nut or citrus trees that are plowed or cultivated. In those areas Case 13 clearances shall apply.
(kkk) For communication conductors across or along public thoroughfares see 84.4–A(6).

Note: Revised February 1, 1948 by Supplement No. 1 (Decision No. 41134, Case No. 4324); January 2, 1962 by Resolution E–1109; February 7, 1964 by Decision No. 66707; March 29, 1966 by Decision No. 70489; August 9, 1966 by Decision No. 71094; September 18, 1967 by Decision No. 72984; March 30, 1968 by Decision No. 73813; January 8, 1980 by Decision No. 91186; March 9, 1988 by Resolution E–3076; November 21, 1990 by Resolution SU–6; January 21, 1992 by Resolution SU–10; and November 6, 1992 by Resolution SU–15, September 20, 1996 by Decision 96–09–097, October 9, 1996 by Resolution SU–40, January 23, 1997 by Decision 97–01–044, January 13, 2005 by Decision No. 0501030 , January 12, 2012 by Decision No. 1201032, and January 21, 2015 by Decision 1501005

# Appendix E
# Clearance of Poles, Towers and Structures from Railroad Tracks

Where poles, towers or other line structures are set in proximity to railroad tracks, the minimum side clearance from the face of a pole, tower or structure to the center line of the tangent railroad track shall be 8 feet 6 inches.

This side clearance may be decreased or shall be increased in accordance with this Commission's General Order 26–D, Sections 3.7, 3.16, 3.20, 8.1, 9.2, 9.3 and 9.4. For tracks used exclusively for Light–rail Transit operations, the side clearances may be further decreased in accordance with this Commission's General Order 143A, Section 9.06.

Clearance requirements above railroads are shown in General Order No. 95, in Rules 37, Table 1, 54.4–B, 56.4–B, 57.4–B, 58.5–B2, 74.4–B, 77.4–A, 84.4–B. 86.4–B, 87.4–B and 113.5.

Note: Revised January 19, 1994 by Resolution SU–25.

# Appendix E
# Guidelines to Rule 35

The following are guidelines to Rule 35.

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances than those listed below to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, fire risk, and vegetation trimming requirements that are applicable to State Responsibility Area lands pursuant to Public Resource Code Sections 4102 and 4293.

| **Voltage of Lines** | **Case 13 of Table 1** | **Case 14 of Table 1** |
|---|---|---|
| Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volts | 4 feet | 6.5 feet |
| Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 volts | 6 feet | 10 feet |
| Radial clearances for any conductor of a line operating at 110,000 or more volts, but less than 300,000 volts | 10 feet | 20 feet |
| Radial clearances for any conductor of a line operating at 300,000 or more volts | 15 feet | 20 feet |

Note: Added November 6, 1992 by Resolution SU–15. Revised September 20, 1996 by Decision No. 96–09–097, August 20, 2009 by Decision No. 09-08-029 and January 12, 2012 by Decision No. 12-01-032.

# Exhibit 27

Decision 17-12-024 December 14, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking to Develop and Adopt Fire-Threat Maps and Fire-Safety Regulations. | Rulemaking 15-05-006 |

# DECISION ADOPTING REGULATIONS TO ENHANCE FIRE SAFETY IN THE HIGH FIRE-THREAT DISTRICT

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# DECISION ADOPTING REGULATIONS TO ENHANCE FIRE SAFETY IN THE HIGH FIRE-THREAT DISTRICT

## Summary

This Decision adopts new regulations to enhance the fire safety of overhead electric power lines and communication lines located in high fire-threat areas. The most significant regulations adopted by this Decision are:

- A new High Fire-Threat District ("HFTD") is added to General Order 95 ("GO 95").[1] The HFTD consists of three areas:
    - **Zone 1** consists of Tier 1 High Hazard Zones ("HHZs") on the map of Tree Mortality HHZs prepared jointly by the United States Forest Service and the California Department of Forestry and Fire Protection ("CAL FIRE"). Tier 1 HHZs are in direct proximity to communities, roads, and utility lines, and represent a direct threat to public safety.
    - **Tier 2** consists of areas on the California Public Utilities Commission's Fire-Threat Map ("CPUC Fire-Threat Map") where there is an elevated risk for destructive utility-associated wildfires. The CPUC Fire-Threat Map is currently in an advanced stage of development.
    - **Tier 3** consists of areas on the CPUC Fire-Threat Map where there is an extreme risk for destructive utility-associated wildfires.
- Amendments to GO 95, Rule 18, to require utilities to (i) prioritize correction of safety hazards based, in part, on whether the safety hazard is located in the HFTD; (ii) correct within six months a Priority Level 2 fire risk that is located in

[1] The purpose of GO 95 is "to formulate, for the State of California, requirements for overhead line design, construction, and maintenance, the application of which will ensure adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead lines and to the public in general." (GO 95, Rule 11.)

Tier 3 of the HFTD; and (iii) correct within 12 months a Priority Level 2 fire risk that is located in Tier 2 of the HFTD.

- Amendments to GO 95, Rule 35, Table 1, to require utilities to maintain the stricter Case 14 vegetation clearances in the HFTD.
- Amendments to GO 95, Rule 38, to increase the effective minimum clearance between wires for new and reconstructed facilities in Tier 3 of the HFTD.
- Amendments to GO 95, Rule 80.1-A, to require minimum patrol and detailed inspection cycles for overhead communication lines in Tier 2 and Tier 3 of the HFTD. Inspections must be conducted twice as often in Tier 3 compared to Tier 2.
- Amendments to GO 95, Rule 80.1-B, to require a minimum intrusive inspection cycle for overhead communication lines in Tier 3 of the HFTD.
- Amendments to GO 95, Appendix E, to increase the recommended time-of-trim clearances between power lines and vegetation in the HFTD.
- Amendments to GO 165, Table 1, to require annual patrol inspections of overhead electric utility distribution facilities in rural Tier 2 and Tier 3 areas of the HFTD.
- Amendments to GO 166, Standard 1, Part E, to require every electric investor-owned utility ("Electric IOU") with overhead power lines in the HFTD to prepare a fire-prevention plan.
- Amendments to Electric Tariff Rule 11 to allow Electric IOUs to disconnect electric service to a customer in the HFTD when:
    - There is a breach of the minimum vegetation clearances required by California Public Resources Code §§ 4292 and 4293 for State Responsibility Areas.
    - The Electric IOU has obtained from an arborist a written determination that a dead, rotten, diseased, leaning, or overhanging tree (or parts thereof) poses an imminent or immediate risk for falling onto a power line.

The fire-safety regulations adopted by this Decision will help to protect public safety in accordance with Public Utilities Code Sections 451 and 8386(a).[2] It is likely that electric utilities and communications infrastructure providers will incur additional but unquantified costs to implement the fire-safety regulations adopted by this Decision. This Decision finds that the additional costs are exceeded by the substantial public-safety benefits of the adopted regulations.

Electric IOUs are authorized to track the costs they incur to implement the regulations adopted by this Decision and to file applications to recover these costs. Electric IOUs shall thereafter seek to recover such costs in their general rate case (GRC) proceedings. Small Incumbent Local Exchange Carriers may use their annual California High Cost Fund-A advice letters to request recovery of the costs they incur to implement the regulations adopted in this proceeding until their next GRC proceedings.

Finally, today's Decision instructs the Director of the Commission's Safety and Enforcement Division ("SED") or the Director's designee (together, "Director") to confer with CAL FIRE regarding the following matters:

- The development of a statewide fire-wind map, under the direction of CAL FIRE, to provide a scientifically sound basis for establishing fire-wind-load standards.
- Adoption of a six-month maximum timeframe for correcting Priority Level 2 fire risks in Tier 2 of the HFTD.

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[2] Section 451 states that "[e]very public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities… as are necessary to promote the safety… of its patrons, employees, and the public." Section 8386(a) states that "[e]ach electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment."

CAL FIRE has agreed to confer with the Director regarding the above matters. After conferring with CAL FIRE, the Director shall submit a written report within six months to the Commission and the Commission's Executive Director that provides the Director's recommendations regarding whether and how to proceed with (1) the development and adoption of a statewide fire-wind map, (2) the development and adoption of fire-wind-load standards and possibly other fire-safety regulations tied to the fire-wind map, and (3) the adoption of a six-month timeframe for correcting Priority Level 2 fire risks in Tier 2 fire-threat areas. The Director shall concurrently post a copy of the report (or a link to the report) on SED's section of the Commission's website.

## 1. Background

This rulemaking proceeding is the successor to Rulemaking (R.) 08-11-005 ("R.08-11-005"). In R.08-11-005, the Commission adopted dozens of new fire-safety regulations in response to devastating Southern California wildfires in October 2007 that were reportedly ignited by power lines. These included the Grass Valley Fire (1,247 acres), the Malibu Canyon Fire (4,521 acres), the Rice Fire (9,472 acres), the Sedgewick Fire (710 acres), and the Witch Fire (197,990 acres). The total area burned by these five power-line fires exceeded 334 square miles.

Several of the fire-safety regulations adopted in R.08-11-005 apply only to areas where there is an elevated risk of power-line fires igniting and spreading rapidly (referred to herein as "high fire-threat areas"). These regulations include:

- A new General Order 95 ("GO 95")[3] rule that sets minimum frequencies for patrol inspections, detailed inspections, and intrusive inspections of aerial communication utility facilities in high fire-threat areas that are (i) attached to the same pole as electric utility facilities, or (ii) in close proximity to overhead electric utility facilities.
- A new GO 95 rule that expands vegetation clearances around power lines in high fire-threat areas of Southern California.
- A new GO 165 rule that increases the frequency of patrol inspections of overhead electric utility distribution facilities in rural high fire-threat areas of Southern California.[4]
- A new GO 166 rule that requires investor-owned electric utilities ("Electric IOUs")[5] in Southern California to prepare and submit plans to prevent power-line fires generally and during extreme fire weather. Electric IOUs in Northern California must assess if there is a credible threat of extreme fire-weather events in their service territories and, if so, to prepare and submit plans to prevent power-line fires from occurring during such events.

The Commission adopted several interim fire-threat maps in R.08-11-005 to designate areas where the previously identified fire-safety regulations apply. Each of the interim maps covers a different part of the State and uses its own method to identify high fire-threat areas. The Commission also commenced the

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[3] GO 95 contains rules for the design, construction, operation, and maintenance of overhead utility facilities such as power lines, communications lines, utility poles, and pole-mounted antennas.

[4] GO 165 prescribes inspection cycles for electric utility distribution facilities.

[5] GO 166 requires, among other things, that every electric utility subject to the Commission's jurisdiction shall annually prepare and submit a plan that sets forth the utility's anticipated responses to emergencies and major outages.

development of a single statewide fire-threat map to designate areas where (1) there is a heightened risk for destructive power-line fires, and (2) where stricter fire-safety regulations should apply.

The Commission instituted the instant rulemaking proceeding, R.15-05-006, to complete the work of R.08-11-005. The general scope of R.15-05-006 is to address the following matters carried over from R.08-11-005:

1. Develop and adopt a statewide fire-threat map that delineates the boundaries of a new High Fire-Threat District where the stronger fire-safety regulations adopted in R.08-11-005 will apply.
2. Determine the need for additional fire-safety regulations in the High Fire-Threat District in light of the statewide fire-threat map adopted pursuant to Item 1.
3. Consider proposals related to the "multiply by" provision in Rule 48 of GO 95, provided that such proposals are consistent with the primary purpose of R.15-05-006 of enhancing the fire safety of overhead utility facilities.
4. Revise GO 95 to include (a) a High Fire-Threat District, (b) maps of the High Fire-Threat District, and (c) any new fire-safety regulations developed pursuant to Items 1 - 3.

The scope and schedule for R.15-05-006 was divided into two parallel tracks. One track focused on the development and adoption of a statewide fire-threat map. The second track focused on the identification, evaluation, and adoption of fire-safety regulations. Each track is summarized below.

### 1.1. The Commission's Fire-Threat Map

A multi-step process has been used to develop the statewide fire-threat map. The first step was to develop Fire Map 1 ("FM 1"), which depicts areas of California where there is an elevated hazard for the ignition and rapid spread of power-line fires due to strong winds, abundant dry vegetation, and other

environmental conditions. These are the environmental conditions associated with the catastrophic power-line fires that burned 334 square miles of Southern California in October 2007.

The Commission adopted FM 1 in Decision ("D.") 16-05-036. FM 1 was developed by the California Department of Forestry and Fire Protection ("CAL FIRE") in collaboration with the Commission's Safety and Enforcement Division ("SED") and the many parties in this proceeding.

The second step is to develop a statewide map of the new High Fire-Threat District where stricter fire-safety regulations apply. Importantly, the High Fire-Threat District Map will incorporate the fire hazards associated with historical power-line fires besides the October 2007 power-line wildfires in Southern California. These other power-line fires include the Butte Fire that burned 71,000 acres in Amador and Calaveras Counties in September 2015. The Commission adopted a work plan for the development of the High Fire-Threat District Map in D.17-01-009, as modified by D.17-06-024.

The High Fire-Threat District Map will be a combination of two maps. These are (1) the United States Forest Service ("USFS") and CAL FIRE's joint map of Tree Mortality High Hazard Zones ("HHZs"); and (2) the California Public Utilities Commission ("CPUC" or "Commission") Fire-Threat Map. The USFS-CAL FIRE joint map of Tree Mortality HHZs is an off-the-shelf product. The CPUC Fire-Threat Map is currently in an advanced stage of development. It will be based on FM 1, several other fire-threat maps identified in D.17-01-009, and input from electric utilities and other stakeholders.

The primary responsibility for the development of the CPUC Fire-Threat Map lies with a small group of utility personnel and consultants, known as the Peer Development Panel ("PDP"), who have expertise in the development of

fire-threat maps. A separate group of independent experts, known as the Independent Review Team ("IRT"), is responsible for reviewing and approving the CPUC Fire-Threat Map developed by the PDP. CAL FIRE selected the members of the IRT and oversees the work of the IRT.

The High Fire-Threat District Map will have three fire-threat areas. **Zone 1** will consist of Tier 1 HHZs on the USFS-CAL FIRE joint map of Tree Mortality HHZs. Tier 1 HHZs are in direct proximity to communities, roads, and utility lines, and are a direct threat to public safety.

**Tier 2** will consist of areas on the CPUC Fire-Threat Map where there is an elevated risk (including likelihood and potential impacts on people and property) from wildfires associated with overhead utility power lines or overhead utility power-line facilities also supporting communication facilities.

**Tier 3** will consist of areas on the CPUC Fire-Threat Map where there is an extreme risk (including likelihood and potential impacts on people and property) from wildfires associated with overhead utility power lines or overhead utility power-line facilities also supporting communication facilities. Tier 3 is distinguished from Tier 2 by having the highest likelihood of utility-associated fire initiation and growth that would impact people or property, and where the most restrictive utility regulations are necessary to reduce utility fire risk.[6]

On July 31, 2017, the PDP served (but did not file) a draft statewide CPUC Fire-Threat Map that delineates the PDP's proposed boundaries for Tier 2 and Tier 3 fire-threat areas. On October 2, 2017, the PDP filed and served the Initial

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[6] The High Fire-Threat District Map will consist of two independent maps. These are (i) Tier 1 HHZs on the USFS-CAL FIRE joint map of Tree Mortality HHZs, and (ii) the CPUC Fire-Threat Map. (D.17-01-009 at 48.)

CPUC Fire-Threat Map that reflects the IRT's review and recommended revisions through September 25, 2017. On October 5, 2017, the PDP filed and served a document that provided summary information regarding the geographic areas covered by the Initial CPUC Fire-Threat Map. On November 17, 2017, the PDP filed and served the IRT-approved CPUC Fire-Threat Map. On November 20, 2017, the PDP filed and served a document that provided the following summary information regarding the geographic areas covered by the IRT-approved CPUC Fire-Threat Map:

**Table 1**
**Geographic Area Covered by the IRT-approved CPUC Fire-Threat Map**
**Square Miles**

| Region | Tier 2 Elevated | Tier 3 Extreme | Tier 2 + Tier 3 |
|---|---|---|---|
| Southern California | 6,352 | 6,070 | 12,421 |
| Northern California | 51,476 | 6,408 | 57,884 |
| Total for Tier | 57,827 | 12,478 | 70,305 |

**Percent of California Land Area**

| Region | Tier 2 Elevated | Tier 3 Extreme | Tier 2 + Tier 3 |
|---|---|---|---|
| Southern California | 13.9% | 13.2% | 27.1% |
| Northern California | 45.7% | 5.6% | 51.3% |
| Total for Tier | 36.5% | 7.8% | 44.3% |

**Source**: *Response of the Peer Development Panel to Administrative Law Judges' October 6, 2017 Ruling – Additional Shape B Map Information* filed on November 20, 2017, at Appendix A, page A-10.

The above table shows that the total land area covered by Tier 2 and Tier 3 on the IRT-approved CPUC Fire-Threat Map is 70,305 square miles. For comparison, the total land area covered by the Interim Fire-Threat Maps is 31,022 square miles.[7]

At the time of today's Decision, it is anticipated that the Commission will adopt a final IRT-approved CPUC Fire-Threat Map in early 2018.

A draft of the High Fire-Threat District Map is contained in Appendix D of today's Decision. The draft map is composed of (1) Tier 1 HHZs on the USFS-CAL FIRE joint map of Tree Mortality HHZs; and (2) Tier 2 and Tier 3 fire-threat areas on the IRT-approved CPUC Fire-Threat Map filed on November 17, 2017.

### 1.2. Proposed Fire-Safety Regulations for the High Fire-Threat District and the Workshop Report

The scope and schedule for R.15-05-006 includes a process for parties to identify, evaluate, and submit proposed fire-safety regulations for the High Fire-Threat District (consisting of Zone 1, Tier 2, and Tier 3 described previously in today's Decision). This process has been led by an ad hoc group known as the Fire Safety Technical Panel ("FSTP"). The FSTP is co-chaired by SED and Southern California Edison Company, and is open to all parties.

The FSTP held 12 days of workshops during the five-month period of February - June 2017. On July 10, 2017, Comcast Phone of California, LLC ("Comcast"), Cox Communications California, LLC ("Cox"), and Crown Castle NG West, Inc. ("Crown Castle") filed and served the *Joint Parties Workshop Report*

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[7] *Response of San Diego Gas & Electric Company (U 902-E) to Administrative Law Judge's August 1 Ruling* filed on August 14, 2017.

*on Fire Safety Regulations* (hereafter, "the Workshop Report") on behalf of themselves and the following parties:

- AT&T California & New Cingular Wireless PCS, LLC ("AT&T").
- Bear Valley Electric Service, a division of Golden State Water Company ("Bear Valley").
- California Cable & Telecommunications Association ("CCTA").
- California Farm Bureau Federation ("CFBF").
- California Municipal Utilities Association ("CMUA").
- The Commission's Safety and Enforcement Division ("SED").
- The City of Laguna Beach ("Laguna Beach").
- Consolidated Communications of California Company ("Consolidated Communications").
- CTIA-The Wireless Association ("CTIA").
- Citizens Telecommunications Company of California Inc. d/b/a Frontier Communications of California (U 1024 C), Frontier Communications of the Southwest Inc. (U 1026 C), and Frontier California Inc. (U 1002 C) (collectively, "Frontier").
- Liberty Utilities (CalPeco Electric) LLC ("Liberty Utilities").
- International Brotherhood of Electrical Workers Local 1245 ("IBEW 1245").
- County of Los Angeles Fire Department ("LACFD").
- Los Angeles Department of Water and Power ("LADWP").
- Mussey Grade Road Alliance ("MGRA").
- PacifiCorp d/b/a Pacific Power ("PacifiCorp").
- Pacific Gas and Electric Company ("PG&E").
- San Diego Gas & Electric Company ("SDG&E").
- Southern California Edison Company ("SCE").
- The Small Local Exchange Carriers ("Small LECs").
- Sacramento Municipal Utility District ("SMUD").
- The Utility Reform Network ("TURN").

The Workshop Report contains 31 proposed fire-safety regulations for the High Fire-Threat District. On July 31, 2017, the following parties filed opening comments regarding the Workshop Report: A coalition of communication infrastructure providers (the "CIP Coalition")[8]; Laguna Beach; CFBF; Liberty Utilities; MGRA; PacifiCorp; PG&E; a coalition of publicly owned electric utilities consisting of CMUA, LADWP, and SMUD (the "Joint POUs"); SCE; SDG&E; SED; and TURN. On August 11, 2017, the following parties filed reply comments: The CIP Coalition,[9] Laguna Beach, Liberty Utilities, MGRA, PacifiCorp, PG&E, the Joint POUs, SCE, SDG&E, SED, and TURN.

Pursuant to D.17-01-009, as modified by the co-assigned Administrative Law Judges' ("ALJs") ruling on July 7, 2017, the parties had an opportunity to file motions for an evidentiary hearing on the proposed fire-safety regulations. No party filed a motion for an evidentiary hearing and none was held.

## 2. Commission Jurisdiction

The purpose of this rulemaking proceeding is to consider and adopt regulations to reduce the fire hazards associated with (1) overhead power-line facilities, and (2) aerial communication facilities located in close proximity to overhead power lines. The California Constitution and the Public Utilities Code ("Pub. Util. Code") provide the Commission with broad jurisdiction to adopt

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[8] The CIP Coalition is comprised of AT&T, CCTA, Comcast, Consolidated Communications, Cox, Crown Castle, CTIA, Frontier, the Small LECs, and T-Mobile West, LLC d/b/a T-Mobile.

[9] The CIP Coalition's reply comments included Time Warner Cable Information Services (California), LLC.

regulations regarding the safety of utility facilities and operations.[10] Utilities are required by Pub. Util. Code § 702 to "obey and comply" with such requirements.[11]

In addition to the Commission's broad jurisdiction to regulate IOUs, Pub. Util. Code §§ 8002, 8037, and 8056 provide the Commission with authority to adopt and enforce rules governing electric transmission and distribution facilities of publicly owned utilities for the limited purpose of protecting the safety of employees and the general public.

The Commission's comprehensive jurisdiction over matters of public safety associated with utility facilities extends to attachments to utility poles by CIPs. Specifically, 47 U.S.C. § 224 provides that the Federal Communications Commission ("FCC") does not have "jurisdiction [under 47 U.S.C. § 224] with respect to rates, terms, and conditions, or access to poles, ducts, conduits, and rights-of-way as provided in subsection (f) for pole attachments in any case where such matters are regulated by a State." The Commission has certified to the FCC that the Commission regulates such matters in conformance with 47 U.S.C. §§ 224(c)(2) and (3).[12] Further, under 47 U.S.C. § 253(b) the Commission may adopt regulations to protect public safety and welfare.

Likewise, the Cable Communications Policy Act of 1984 specifically grants states jurisdiction over cable service in safety matters. (47 U.S.C. § 556(a).) The California Legislature asserted such jurisdiction in Pub. Util. Code § 768.5, which

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[10] Cal. Constitution, Art. XII, §§ 3 and 6, and Pub. Util. Code §§ 216, 701, 761, 768, 770, 1001, 8037, and 8056. See also *SDG&E v. Cal. Super.* (1996) 13 Cal.4th 893, 923-924.

[11] See also Pub. Util. Code §§ 761, 762, 767.5, 768, 770.

[12] D.98-10-058, 82 CPUC2d 510, 531, as modified by D.00-04-061, 6 CPUC3d 1, 5.

gives the Commission authority to regulate cable companies with respect to the safe operation, maintenance, and construction of their facilities.

The Commission has enacted an extensive set of safety regulations governing utility facilities and operations, including GO 95. A major goal of GO 95 is to minimize fire hazards.

## 3. Criteria for the Adoption of New Fire-Safety Regulations

The primary standard we will use to decide whether to adopt the proposed fire-safety regulations in the Workshop Report is whether the proposals are likely to reduce fire hazards in the High Fire-Threat District at a reasonable cost. This is consistent with Pub. Util. Code § 451, which states, in relevant part, as follows:

> All charges demanded or received by any public utility… shall be just and reasonable… Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities… as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

Because this is a quasi-legislative rulemaking proceeding, today's Decision may rely on legislative facts[13] obtained from written submissions in this proceeding, such as the Workshop Report and written comments. We may also

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[13] A quasi-legislative proceeding establishes policies or rules affecting a class of regulated utilities. (Rule 1.3(d) of the Commission's Rules of Practice and Procedure.) Legislative facts are general facts that help the Commission to decide questions of law and policy and discretion. (Rule 13.3(c) of the Commission's Rules of Practice and Procedure.)

draw on evidence from past proceedings, our experience and expertise in regulating utilities, our current policies, and common sense.[14]

Pub. Util. Code § 1708.5(f) provides that "the commission may conduct any proceeding to adopt, amend, or repeal a regulation using notice and comment rulemaking procedures, without an evidentiary hearing, except with respect to a regulation being amended or repealed that was adopted after an evidentiary hearing, in which case the parties to the original proceeding shall retain any right to an evidentiary hearing accorded by Section 1708." The Commission provided notice of Order Instituting Rulemaking ("OIR") 15-05-006 to all potential parties, including regulated electric corporations, municipal electric utilities, and CIPs operating in California.[15] The Commission provided parties with an opportunity to request an evidentiary hearing regarding the matters that are addressed in today's Decision in accordance with the procedure and schedule set forth in D.17-01-009, as modified by the ALJs' ruling issued on July 7, 2017. No party requested an evidentiary hearing and none was held.

## 4. Proposed Regulations

The Workshop Report contains 31 proposed regulations ("PRs") to revise GO 95, GO 165, GO 166, and Electric Tariff Rule 11. There are two consensus PRs and 29 contested PRs. Below, we first address the two consensus PRs, followed by the 29 contested PRs.

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[14] D.06-06-071 at 26; D.06-12-029 at 13 – 14; D.04-03-041 at 11; and D.99-07-047, 1 CPUC3d 627, 634 – 636.

[15] OIR 15-05-006 at 19-20 and Ordering Paragraph 23.

PacifiCorp states that because its fire season occurs during the months of June through August, a six-month correction period for fire risks discovered during inspection cycles that start in mid-March would not result in any fire-risk mitigation until the following fire season. PacifiCorp is also concerned that the six-month deadline could force repairs to take place during winter months.

PG&E opposes PR 4/AP-1 because it could result in resource gaps and increased costs to complete work in the six-month timeframe given the varied terrain in PG&E's service territory. TURN opposes PR 4/AP-1 because the proponent did not provide a cost estimate for the proposal.

#### 4.2.3.3 Discussion

The issue before us is whether to adopt PR 3 or PR 4/AP-1. Our standard for deciding this issue is whether PR 3, PR 4/AP-1, or some combination thereof will enhance fire safety at a reasonable cost.

##### 4.2.3.3.1 Rule 18-A(2)(a)

Rule 18-A(2)(a), as modified previously in today's Decision, requires utilities to prioritize the correction of safety hazards based on six factors, including whether the safety hazard is located in a Tier 3 fire-threat area in Southern California. In PR 3, SDG&E proposes to modify Rule 18-A(2)(a) so that it applies to safety hazards located in Tier 2 and Tier 3 fire-threat areas anywhere in the State. In PR 4/AP-1, the CIP Coalition proposes to modify Rule 18-A(2)(a) so that it applies to safety hazards located in Zone 1, Tier 2, and Tier 3 fire-threat areas statewide (i.e., located in the High Fire-Threat District statewide).

We conclude that it is reasonable to adopt the CIP Coalition's PR 4/AP-1. The High Fire-Threat District consists of areas where there is an elevated or extreme risk for utility-associated wildfires. The precepts of common sense and public safety dictate that when utilities discover facilities that pose a fire hazard,

they should consider if the fire hazard is in Zone 1, Tier 2, or Tier 3 of the High Fire-Threat District when prioritizing the correction of the fire hazard. Indeed, we believe it would be reckless and contrary to Pub. Util. Code § 451 if utilities were to ignore the location of a fire hazard with respect to the High Fire-Threat District when prioritizing the correction of the fire hazard.

Although the CIP Coalition did not provide a cost estimate for PR 4/AP-1, we conclude that it is unlikely the costs will be significant. The adopted amendment to Rule 18-A(2)(a) requires utilities to do nothing more than consider where a fire hazard is located with respect to the High Fire-Threat District when prioritizing the correction of the fire hazard. While utilities may incur some costs to implement procedures for carrying out this prioritization, we conclude that such costs are exceeded by the public-safety benefits.

We decline to adopt SDG&E's PR 3 to the extent that SDG&E's proposal omits Zone 1 fire-threat areas from Rule 18-A(2)(a). SDG&E did not explain why it omitted Zone 1. We conclude that it is reasonable to include Zone 1 fire-threat areas in Rule 18-A(2)(a) for the previously stated reasons.

We disagree with TURN that there is insufficient information to properly assess the cost-effectiveness of our adopted amendments to Rule 18-A(2)(a). We find that there are substantial public-safety benefits, as well as public policy considerations,[27] to justify our adopted amendments to Rule 18-A(2)(a).

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[27] The *Safety Policy Statement of the California Public Utilities Commission*, dated July 10, 2014, states at 1 that it is the Commission's policy to continually reduce the safety risks posed by the utilities regulated by the Commission. The *Safety Policy Statement* is at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/VisionZero4Final621014_5_2.pdf.

Our adopted amendments to Rule 18-A(2)(a) are set forth in Appendix B of today's Decision. We also correct a non-substantive typographical error in Rule 18-A(1)(b) noted by the CIP Coalition.[28]

#### 4.2.3.3.2 Rule 18-A(2)(a)(ii)

Rule 18-A(2)(a)(ii), as modified previously in today's Decision, requires utilities to correct within 12 months a Priority Level 2 fire risk that is located in Tier 3 of the High Fire-Threat District in Southern California.[29] All other Priority Level 2 fire risks must be corrected within 59 months. These are maximum allowed timeframes for correcting fire risks. Rule 18 requires a Priority Level 2 fire risk to be corrected in less than 12 months or 59 months if doing so is necessary to protect public safety.

In PR 3, SDG&E proposes to amend Rule 18-A(2)(a)(ii) to require Priority Level 2 fire risks to be corrected within six months if they are located in Tier 2 or Tier 3 of the High Fire-Threat District anywhere in the State. In PR 4/AP-1, the CIP Coalition proposes to require Priority Level 2 fire risks to be corrected within 6 months if they are located in Tier 3 statewide, and within 59 months if they are located in Tier 2 statewide.

For the reasons set forth below, we conclude that it is reasonable to adopt PR 3 and PR 4/AP-1 to the extent these proposals seek to amend Rule 18-A(2)(a)(ii) to require Priority Level 2 fire risks to be corrected within 6 months if they are located in a Tier 3 fire-threat area anywhere in the State, and

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[28] Workshop Report at B-28.

[29] Rule 18-A(2)(a)(ii) defines "Priority Level 2" as "[v]ariable (non-immediate high to low) safety and/or reliability risk."

within 12 months if they are located in a Tier 2 fire-threat area anywhere in the State. We decline to adopt all other aspects of these proposals.

Tier 3 fire-threat areas pose an extreme risk for utility-associated wildfires. Given the severity of the wildfire risk, we conclude that public safety requires that we amend Rule 18-A(2)(a)(ii) to provide a maximum of six months to correct Priority Level 2 fire risks in Tier 3 fire-threat areas. Similarly, Tier 2 fire-threat areas pose an elevated risk for utility-associated wildfires. Given the elevated wildfire risk, we conclude that public safety requires that we amend Rule 18-A(2)(a)(ii) to provide a maximum of 12 months to correct Priority Level 2 fire risks in Tier 2 fire-threat areas. We emphasize that 6 months is the maximum time allowed to correct Priority Level 2 fire risks in Tier 3 fire-threat areas, and 12 months in Tier 2 fire-threat areas. Utilities have a duty under Rule 18,[30] Rule 31.1,[31] and Pub. Util. Code § 451[32] to correct Priority Level 2 fire risks sooner if doing so is necessary to protect public safety.

We decline to adopt at this time a six-month correction timeframe for Priority Level 2 fire risks in Tier 2 as recommended by SDG&E. The land area covered by Tier 2 on the IRT-approved CPUC Fire-Threat Map is 57,827 square

30 Rule 18-A(1)(a) requires each utility to take appropriate action to remedy safety hazards posed by its facilities.

31 Rule 31.1 states that a "if an intended use or known local conditions require a higher standard than the particulars specified in in [GO 95] to enable the furnishing of safe, proper, and adequate service, the company shall follow the higher standard."

32 Pub. Util. Code § 451 requires every public utility to "furnish and maintain… service, instrumentalities, equipment, and facilities… as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

miles, or approximately 37 percent of the land area of California.[33] Because of the large area covered by Tier 2, and given that Priority Level 2 includes non-immediate, low fire risks, we are not convinced that a six-month deadline for correcting every Priority Level 2 fire risk in Tier 2 is cost-effective or necessary to protect public safety.

We realize that there may be situations where a utility cannot meet the correction timeframes adopted by today's Decision for Priority Level 2 fire risks in Tier 2 and Tier 3 fire-threat areas because of circumstances beyond the utility's control. In these situations, Rule 18-A(2)(b) allows correction times to be extended for good cause, such as third-party refusal to provide access, severe weather, and system emergencies.

We do not expect the correction timeframes adopted by today's Decision for Priority Level 2 fire risks will increase costs significantly for utilities in the long run. Rule 18 has always required utilities to correct Priority Level 2 fire risks. While today's Decision requires utilities to correct fire risks sooner if they are located in Tier 2 or Tier 3, today's Decision does not affect the total number of Priority Level 2 fire risks that must be corrected over time.

We disagree with TURN's position that there is insufficient information in the record of this proceeding to assess the reasonableness and cost-effectiveness of the shortened correction timeframes adopted by today's Decision. Fire risks in Tier 2 and Tier 3 fire-threat areas are a major threat to public safety. To the extent a utility incurs significant costs to comply with Rule 18-A(2)(a)(ii) because of today's Decision, we conclude that the costs are offset by the substantial

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[33] *Response of the Peer Development Panel to Administrative Law Judges' October 6, 2017 Ruling – Additional Shape B Map Information* filed on November 20, 2017, at Appendix A, page A-10.

public-safety benefits of reducing the risk of utility-associated wildfires occurring in Tier 2 (elevated) and Tier 3 (extreme) fire-threat areas.

The text of 18-A(2)(a)(ii), as amended by today's Decision, is set forth in Appendix B of today's Decision. We note that the amendments to Rule 18 adopted by today's Decision may be supplemented and/or superseded by revisions to Rule 18 that are the subject of R.16-12-001.[34]

#### 4.2.3.3.3 Further Consideration of Reduced Timeframe for Correcting Priority Level 2 Fire Risks

We intend to further consider the efficacy of reducing the timeframe for correcting Priority Level 2 fire risks in Tier 2 from 12 months to 6 months as recommended by SDG&E. To this end, we will instruct the Director of the Commission's SED or the Director's designee to confer with CAL FIRE, within the context of the Interagency Fire Safety Working Group established by the CPUC-CAL FIRE Memorandum of Understanding ("MOU"), as to whether it would be cost-effective to adopt a six-month correction timeframe (or other reduced timeframe) for Priority Level 2 fire risks in Tier 2 fire-threat areas. We discuss this matter further in Section 7 of today's Decision.

### 4.2.4. Proposed Regulation 5 re: GO 95, Rule 31.1

PR 5, proposed by SDG&E, is essentially identical to SDG&E's PR 3 that we addressed previously in Section 4.2.3.3.2 of today's Decision. Both PR 5 and PR 3 would allow a maximum of six months to correct "[a]ny equipment conditions or facilities that pose an elevated fire-ignition risk in Tiers 2 and 3 of

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[34] The scope of R.16-12-001 is to consider whether to eliminate Rule 18 or, alternatively, consider specified amendments to Rule 18, including whether to eliminate utilities' authority under Rule 18 to defer the correction of overhead utility facilities that pose a risk to safety and/or reliability. (OIR 16-12-001 at 2.)

the High Fire-Threat District.[35]" The main difference between PR 5 and PR 3 is the specific rule within GO 95 that would be amended. PR 5 would amend Rule 31.1 and PR 3 would amend Rule 18.

We decline to adopt PR 5 to the extent it seeks the same amendments to Rule 31.1 that we adopt for Rule 18-A(2)(a)(ii) in Section 4.2.3.3.2 of today's Decision. We find that it would be redundant for Rule 31.1 to contain the same text as Rule 18-A(2)(a)(ii). We reject the remainder of PR 5 for the same reasons we reject the corresponding parts of PR 3 in Section 4.2.3.3.2 of today's Decision.

#### 4.2.5. Proposed Regulation 6 re: GO 95, Rule 31.5

##### 4.2.5.1 Summary of Proposal

Rule 31.5 of GO 95 requires utilities to consider the joint use of poles when constructing or reconstructing overhead facilities. Rule 31.5 further states that "[n]othing herein shall be construed as... granting authority for the use of any poles without the owner's consent (see Rule 32.2 and Section IX)."[36]

In PR 6, SDG&E proposes to amend Rule 31.5 to state that all pole attachments in Tiers 2 and 3 of the High Fire-Threat District "must have the consent of a pole owner or granting authority prior to any construction," and that any attachment without such consent may be reported to the Commission.

The text of SDG&E's proposed revisions to Rule 31.5 is contained in Appendix A of today's Decision. SDG&E recommends that its proposed

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[35] Workshop Report at B-39.

[36] For reference, Rule 32.2 concerns the arrangement of circuits with different voltage classifications and states "[i]t is recommended that lines be arranged by mutual agreement of those concerned...." Section IX provides special rules for all classes of lines on joint poles, and contains the same statement as Rule 31.5: "[n]othing herein shall be construed as... granting authority for the use of any poles without the owner's consent."

things, strategies for increased non-discriminatory access to utility poles by competitive communications providers, the impact of such increased access on safety, and how to ensure the integrity of the affected communications and electric supply infrastructure.[38]

#### 4.2.6. Proposed Regulation 7, Alternative Proposal 1, and Alternative Proposal 2 re: GO 95, Rule 35, Table 1, Case 14

#### 4.2.6.1 Summary of Proposals

GO 95, Rule 35, Table 1, Case 14 ("Case 14") specifies minimum radial clearances between bare line conductors and vegetation in the high fire-threat areas of Southern California on the Interim Fire-Threat Maps. Case 13 specifies the minimum vegetation clearances everywhere else in California. The following table lists the minimum vegetation clearances for Case 14 and Case 13:

[38] Combined Order Instituting Investigation 17-06-027 and Order Instituting Rulemaking 17-06-028 at 1.

| **Table 3a**<br>**GO 95, Rule 35, Table 1, Case 14**<br>**Minimum Radial Clearance Between Power Lines and Vegetation in High Fire-Threat Areas of Southern California**<br>**Kilovolts (kV)** | | | | |
|---|---|---|---|---|
| **0.75 – 2.4 kV** | **2.4 – 72 kV** | **72 – 110 kV** | **110 – 500 kV** | **>500 kV** |
| 18 inches | 48 inches | 72 inches | 120 inches | 120 inches<br>+ 0.4 inch for each kV >500 |

| **Table 3b**<br>**GO 95, Rule 35, Table 1, Case 13**<br>**Minimum Radial Clearance Between Power Lines and Vegetation in all other parts of California** | |
|---|---|
| **0.75 – 300 kV** | **>300 kV** |
| 18 – 37.5 inches,<br>depending on voltage | 75 inches<br>+ 0.2 inch for each kV >300 |
| All Clearances in Tables 3a and 3b for Normal Annual Weather Variations. | |

In PR 7, the FSTP proposes to replace the provisions in Case 14 that pertain specifically to high fire-threat areas in Southern California on the Interim Fire-Threat Maps with provisions that refer to Tier 3 of the High Fire-Threat District in Southern California.

In PR 7/AP-1, SED proposes to amend Case 14 so that the minimum vegetation clearances in Case 14 apply to the entire High Fire-Threat District (Zone 1, Tier 2, and Tier 3) statewide. In PR 7/AP-2, PG&E proposes to amend Case 14 so that the minimum vegetation clearances in Case 14 apply to Tier 3 of the High Fire-Threat District statewide. The following table summarizes the geographic area where Case 14 would apply under each proposal:

| **Table 4**<br>**Geographic Area Subject to Case 14** | | | |
|---|---|---|---|
| **Current** | **PR 7** | **PR 7/AP-1** | **PR 7/AP-2** |
| • Southern Calif.<br>• High Fire-Threat Areas on the Interim Fire-Threat Maps | • Southern Calif.<br>• Tier 3 of the High Fire-Threat District | • Statewide<br>• Entire High Fire-Threat District (Zone 1, Tier 2, and Tier 3) | • Statewide<br>• Tier 3 of the High Fire-Threat District |

The text of the FSTP's, SED's, and PG&E's proposed revisions to Case 14 is contained in Appendix A of today's Decision.

The FSTP and PG&E each recommend that its proposed revisions to Case 14 take effect 12 months after the Commission's adoption of the High Fire-Threat District Map. SED recommends that its proposed revisions take effect 36 months after the adoption of the High Fire-Threat District Map.

None of the proponents provided a cost estimate for its proposal, although PG&E states that the additional costs of maintaining increased vegetation clearances in Tier 3 fire-threat areas statewide should be mitigated because California Public Resources Code Section 4293 ("Cal. Pub. Res. Code § 4293") already requires 48 inches of radial clearance between bare line conductors and vegetation in State Responsibility Areas ("SRAs").

#### 4.2.6.2 Positions of the Parties

**PR 7 (FSTP)**

PR 7 is supported by IBEW 1245, Liberty Utilities, PacifiCorp, PG&E, and SCE. The position of the supporters is encapsulated by Liberty Utilities' statement that it supports PR 7 because it is not cost prohibitive and protects safety in the most fire-prone areas of the State.

Most parties take a neutral position with respect to PR 7, including the majority of the CIP parties, Laguna Beach, MGRA, the Joint POUs, and SDG&E.

LACFD, SED, and TURN oppose PR 7. SED opposes PR 7 because it is limited to Tier 3 fire-threat areas in Southern California. SED contends that Case 14 should apply to the entire High Fire-Threat District statewide as recommended by SED in PR 7/AP-1. TURN opposes PR 7 on the basis of insufficient information regarding its cost-effectiveness.

**PR 7/AP-1 (SED)**

SED submits that PR 7/AP-1 is in the public interest because, in SED's view, the Commission's vegetation-related fire-safety regulations should apply throughout the High Fire-Threat District. SED's PR 7/AP-1 achieves this objective while the alternatives (PR 7 and PR 7/AP-2) do not.

PR 7/AP-1 is supported by IBEW 1245, LACFD, and SDG&E. IBEW 1245 states that the fire-safety benefits of PR 7/AP-1 are presumptively cost-effective. IBEW 1245 contends that the Commission should not reject PR 7/AP-1 because of the inability to measure how many fires will avoided by adopting PR 7/AP-1.

Most parties take a neutral position on PR 7/AP-1, including a majority of the CIPs, Bear Valley, Laguna Beach, and MGRA.

PR 7/AP-1 is opposed by the Joint POUs, Liberty Utilities, PacifiCorp, PG&E, SCE, and TURN. Liberty Utilities and PG&E contend that PR 7/AP-1 does not mitigate the fire hazard of trees falling onto power lines.
Liberty Utilities adds that the map for Zone 1 of the High Fire-Threat District will be updated every two years, making it difficult to plan for tree trimming.

PG&E asserts that SED offered no evidence that trees growing into power lines are a major source of wildfires. Thus, PG&E argues, extending the Case 14

vegetation clearances to the High Fire-Threat District statewide would needlessly expand the scope of Case 14.

PacifiCorp contends that PR 7/AP-1 is not cost-effective, operationally practical, or necessary. PacifiCorp further contends that it is inappropriate to require the same vegetation clearances for both Tiers 2 and 3 of the High Fire-Threat District because each tier has a different fire-risk level.

TURN opposes PR 7/AP-1 on the basis of insufficient information regarding its cost-effectiveness.

**PR 7/AP-2 (PG&E)**

PG&E submits that its PR 7/AP-2 is in the public interest because, in part, Cal. Pub. Res. Code § 4293 already requires four feet of clearance between bare line conductors and vegetation in SRAs during fire season. Extending this 4-foot clearance to a year-round requirement will not add much cost for utility ratepayers and will eliminate the yo-yo effect where the clearance requirement changes from 4 feet to 18 inches depending on the season.

Bear Valley, the Joint POUs, IBEW 1245, and PacifiCorp support PR 7/AP-2. Most of the CIP parties, Laguna Beach, Liberty Utilities, MGRA, SCE, and SDG&E take a neutral position with respect to PR 7/AP-2.

LACFD, SED, and TURN oppose PR 7/AP-2. SED's opposition rests primarily on PR 7/AP-2's exclusion of Zone 1 and Tier 2 fire-threat areas from the scope of Case 14. TURN opposes PR 7/AP-2 on the basis of insufficient information regarding its cost-effectiveness.

#### 4.2.6.3 Discussion

The issue before us is whether to adopt PR 7, PR 7/AP-1, or PR 7/AP-2, or some combination thereof. Our standard for deciding this issue is whether each PR, or some combination thereof, will enhance fire safety in the High Fire-Threat

District at a reasonable cost. We address each of these proposed regulations in the following order: PR 7, PR 7/AP-2, and PR 7/AP-1.

#### 4.2.6.3.1 PR 7

Case 14 requires increased radial clearances between bare line conductors and vegetation in the high fire-threat areas of Southern California on the Interim Fire-Threat Maps. In D.17-01-009, the Commission determined that all existing fire-safety regulations that apply only to high fire-threat areas in Southern California on the Interim Fire-Threat Maps shall transfer to Tier 3 fire-threat areas of the High Fire-Threat District in Southern California. The Commission further held that parties could present recommendations in the current proceeding for adjusting the areas of the High Fire-Threat District where the transferred regulations should apply.[39]

PR 7 modifies Case 14 to conform to D.17-01-009. Therefore, we will adopt PR 7 to the extent the proposal implements the Commission's directive in D.17-01-009 to transfer Case 14 to Tier 3 fire-threat areas of the High Fire-Threat District in Southern California. We decline to adopt PR 7 to the extent the intent of this proposal is to confine the application of Case 14 to Tier 3 fire-threat areas in Southern California. As discussed below in the context of SED's PR 7/AP-1, we conclude that in order to protect public safety, Case 14's vegetation clearances should apply to all of the High Fire-Threat District statewide.

We decline to consider TURN's position that there is insufficient information to assess the cost-effectiveness of PR 7. We previously determined in D.17-01-009 that existing fire-safety regulations that apply only to high

[39] D.17-01-009 at 52 and 56, and Ordering Paragraph 10.

fire-threat areas in Southern California on the Interim Fire-Threat Maps should transfer to Tier 3 fire-threat areas of the High Fire-Threat District in Southern California. PR 7 implements the Commission's determination in D.17-01-009 with respect to Case 14. We will not revisit our determination here.

#### 4.2.6.3.2 PR 7/AP-2

PG&E's PR 7/AP-2 seeks to amend Case 14 so that it applies to Tier 3 fire-threat areas statewide. With one condition, we will adopt PR 7/AP-2 for the reasons set forth below. The one condition is that our adoption of PR 7/AP-2 does not preclude our considering and adopting SED's PR 7/AP-1 that is addressed in Section 4.2.6.3.3 below.

A general principle that we employ in today's Decision is that an existing GO 95 fire-safety regulation that applies only to high fire-threat areas in Southern California on the Interim Fire-Threat Maps should be amended to apply to Tier 3 fire-threat areas of the High Fire-Threat District statewide. The Commission recognized in R.08-11-005 that parts of Southern California faced extreme utility-associated wildfire risks, as demonstrated by the catastrophic wildfires in October 2007. To address this extreme wildfire risk, the Commission in R.08-11-005 amended GO 95 to include several new fire-safety regulations that applied only to high fire-threat areas in Southern California on the Interim Fire-Threat Maps adopted in that proceeding.[40] The High Fire-Threat District Map that is nearing completion in the current proceeding will substantially improve the Commission's ability to identify areas where there are extreme

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[40] The Commission in R.08-11-005 also adopted significant new inspection requirements for specified CIP facilities located in high fire-threat areas throughout California, not just in Southern California.

utility-associated wildfire risks throughout the State. Such areas are designated as Tier 3 fire-threat areas on the High Fire-Threat District Map.

We conclude that existing fire-safety regulations that apply only to high fire-threat areas in Southern California on the Interim Fire-Threat Maps should apply to Tier 3 fire-threat areas of the High Fire-Threat District statewide. These fire-safety regulations were adopted for the specific purpose of addressing extreme utility-associated wildfire risks. We find that in order to protect public safety, it is vital that these fire-safety regulations, including Case 14 at issue here, should apply to Tier 3 extreme fire-threat areas throughout California.

PG&E did not provide a cost estimate for extending the geographic scope of Case 14 from high fire-threat areas in Southern California to Tier 3 statewide. However, the record for this proceeding indicates that the costs will not be excessive. The following table compares the geographic area covered by Tier 3 statewide to the high fire-threat areas in Southern California on the Interim Fire-Threat Maps:

| **Table 5**<br>**Size of Geographic Area Where Case 14 Vegetation Clearances Apply** | |
|---|---|
| **Geographic Area** | **Size of Area (Square Miles)** |
| Southern California. High Fire-Threat Areas on the Interim Fire-Threat Maps [1] | 9,629 [2] |
| Statewide. Tier 3 extreme fire-threat areas of the High Fire-Threat District (based on the IRT-approved CPUC Fire-Threat Map filed on November 17, 2017) | Tier 3 in South. Calif.: 6,070<br>Tier 3 in North. Calif: 6,408<br>Tier 3 in All Calif.: 12,478 [3] |
| **Note 1**: The Interim Fire-Threat Maps in this Table are (1) the SDG&E Fire-Threat Map, and (2) the FRAP Map for the remainder of Southern California.<br>**Note 2**: Source of the listed square miles is the *Response of San Diego Gas & Electric Company (U 902-E) to Administrative Law Judge's August 1 Ruling*, filed on August 14, 2017, at Attachment A, page 5.<br>**Note 3**: Source of the listed square miles is the *Response of the Peer Development Panel to Administrative Law Judges' October 6, 2017 Ruling – Additional Shape B Information*, filed on November 20, 2017, at Attachment A, page A-10. | |

The above table shows that Case 14 applies to 9,629 square miles of high fire-threat areas in Southern California on the Interim Fire-Threat Maps, compared to 12,478 square miles in Tier 3 fire-threat areas statewide on the IRT-approved CPUC Fire-Threat Map. To the extent a utility incurs a significant increase in costs to comply with Case 14 because of today's Decision, we conclude that the costs are offset by the substantial public-safety benefits that will result from the mitigation of vegetation-related fire risks in Tier 3 fire-threat areas. The efficacy of such mitigation will be enhanced by the much greater precision the CPUC Fire-Threat Map will provide in identifying areas where

there is an extreme utility-associated wildfire risk compared to the Interim Fire-Threat Maps.[41]

We recognize that the size of the statewide Tier 3 area listed in the above table (12,478 square miles) is from the IRT-approved CPUC Fire-Threat Map, not the final CPUC High Fire-Threat Map that the Commission will ultimately adopt.[42] Nonetheless, we conclude that the IRT-approved CPUC Fire-Threat Map provides a reasonable estimate for the size of the statewide Tier 3. We do not anticipate that the size of the statewide Tier 3 on the final CPUC Fire-Threat Map will increase to such a large degree relative to the IRT-approved CPUC Fire-Threat Map as to invalidate our previous conclusion that costs incurred by utilities to implement Case 14 in Tier 3 statewide are exceeded by the public-safety benefits.

#### 4.2.6.3.3 PR 7/AP-1

We previously determined that the increased vegetation clearances required by Case 14 should apply to Tier 3 fire-threat areas statewide. Here, we consider if the Case 14 vegetation clearances should apply to Zone 1 and Tier 2 fire-threat areas statewide as recommended by SED in PR 7/AP-1.

Power lines must be kept clear of vegetation at all times to prevent wildfires and outages. Wildfires ignited by vegetation contact with power lines can potentially grow to great size and cause enormous destruction in Zone 1 and Tier 2 fire-threat areas. This fact is illustrated by the following map that shows

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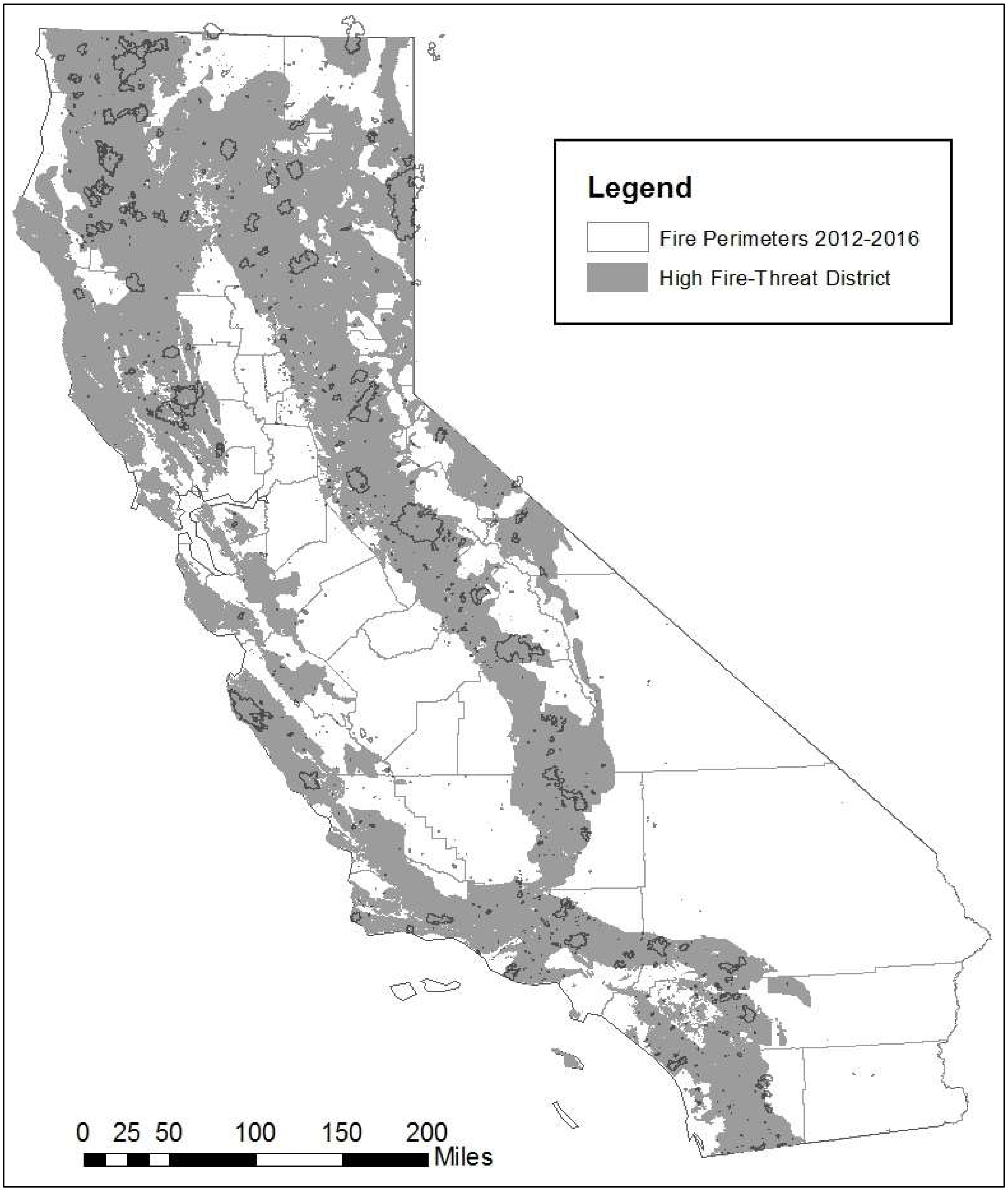
[41] The CPUC Fire-Threat Map is designed to identify areas throughout the State where there is an elevated or extreme utility-associated wildfire risk, whereas the Interim Fire-Threat Maps are not well suited for this purpose. (D.12-01-032 at Findings of Fact 17–20.)

[42] The CPUC Fire-Threat Map will be one of the two maps that comprise the High Fire-Threat District Map.

the footprint of large wildfires (from all causes) during 2012-2016 overlaid on the draft map of the High Fire-Threat District (i.e., Zone 1, Tier 2, and Tier 3):

**Figure 1**

**Draft High Fire-Threat District Map and 2012-2016 Wildfire Perimeters**



The above map does not reflect the many large wildfires that occurred in the footprint for the High Fire-Threat District before 2012 or after 2016, such as the catastrophic wildfires in Southern California in October 2007 and in Northern California in October 2017.

For the preceding reasons, we conclude that it is in the public interest to adopt SED's PR 7/AP-1 and thereby apply the increased vegetation clearance requirements of Case 14 to Zone 1 and Tier 2 fire-threat areas statewide. We recognize that today's Decision significantly increases the geographic area where Case 14 applies. Prior to today's Decision, Case 14 applied to high fire-threat areas in Southern California depicted on the Interim Fire-Threat Maps. Today's Decision amends Case 14 so that it applies to the High Fire-Threat District (i.e., Zone 1, Tier 2, and Tier 3 fire-threat areas) statewide. The following table lists the geographic areas covered by Case 14 before and after today's Decision:

**Table 6**
**Geographic Area Covered by Case 14**
**(Square Miles)**

| | **Southern Calif.** | **Northern Calif.** | **Total Calif.** |
|---|---|---|---|
| **Before Today's Decision** [1] | 9,629 | 0 | 9,629 |
| **After Today's Decision** [2] | 12,421 | 57,884 | 70,305 |
| **Difference** | 2,792 | 57,884 | 60,676 |

**Note 1**: Interim Fire-Threat Maps.
**Note 2**: IRT-approved CPUC Fire-Threat Map filed on November 17, 2017.

The above table shows that today's Decision increases the area covered by Case 14 by 60,676 square miles for all of California.[43] Although SED did not provide an estimate of the costs that utilities would incur, we find that the costs will not be unduly burdensome. This is because, in large part, the following preexisting programs and statutes already require electric utilities to maintain increased vegetation clearances in much of the High Fire-Threat District.

**Tree Mortality High Hazard Zone (HHZ)**

Zone 1 of the High Fire-Threat District consists of the Tier 1 HHZ on the USFS - CAL FIRE joint map of Tree Mortality HHZs. The Tier 1 HHZ is in direct proximity to communities, roads, and utility lines. As such, it represents a direct threat to public safety.[44]

A great deal of tree removal has already occurred, and continues to occur, to reduce the fire risk posed by dead and diseased trees in Zone 1 pursuant to the Governor's October 30, 2015 Emergency Proclamation.[45] Specifically, the Emergency Proclamation ordered state agencies, utilities, and local governments "to remove dead or dying trees in [Tree Mortality HHZs] that threaten powerlines, roads, other evacuation corridors and other existing structures." As part of this work, CAL FIRE identified ten High Priority Counties most in need of addressing tree mortality issues, all of which are located partially or wholly

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[43] Most of the Zone 1 fire-threat area overlaps with Tiers 2 and 3 fire-threat areas.

[44] Almost all of Zone 1 overlaps with Tier 3, Tier 2, and/or SRAs. In fact, approximately 21,616 acres (34 square miles), representing less than three percent of the current Zone 1, is located outside of Tier 3, Tier 2, and SRAs.

[45] On September 1, 2017, by Executive Order B-42-17, the Governor continued the orders and provisions in his October 30, 2015 Emergency Proclamation.

within PG&E's service territory.[46] In 2016, PG&E removed approximately 236,000 dead or dying trees. PG&E estimates that it will remove 158,000 trees in 2017.[47]

**State Responsibility Areas**

The increased vegetation clearances mandated by Case 14 are identical to the vegetation clearances established by Cal. Pub. Res. Code § 4293 for power lines with voltages in the range of 2.4 kV – 500 kV in SRAs. As a result, electric utilities should incur little or no additional costs to implement Case 14 for power lines in areas where SRAs overlap the High Fire-Threat District. The following map shows this overlap:[48]

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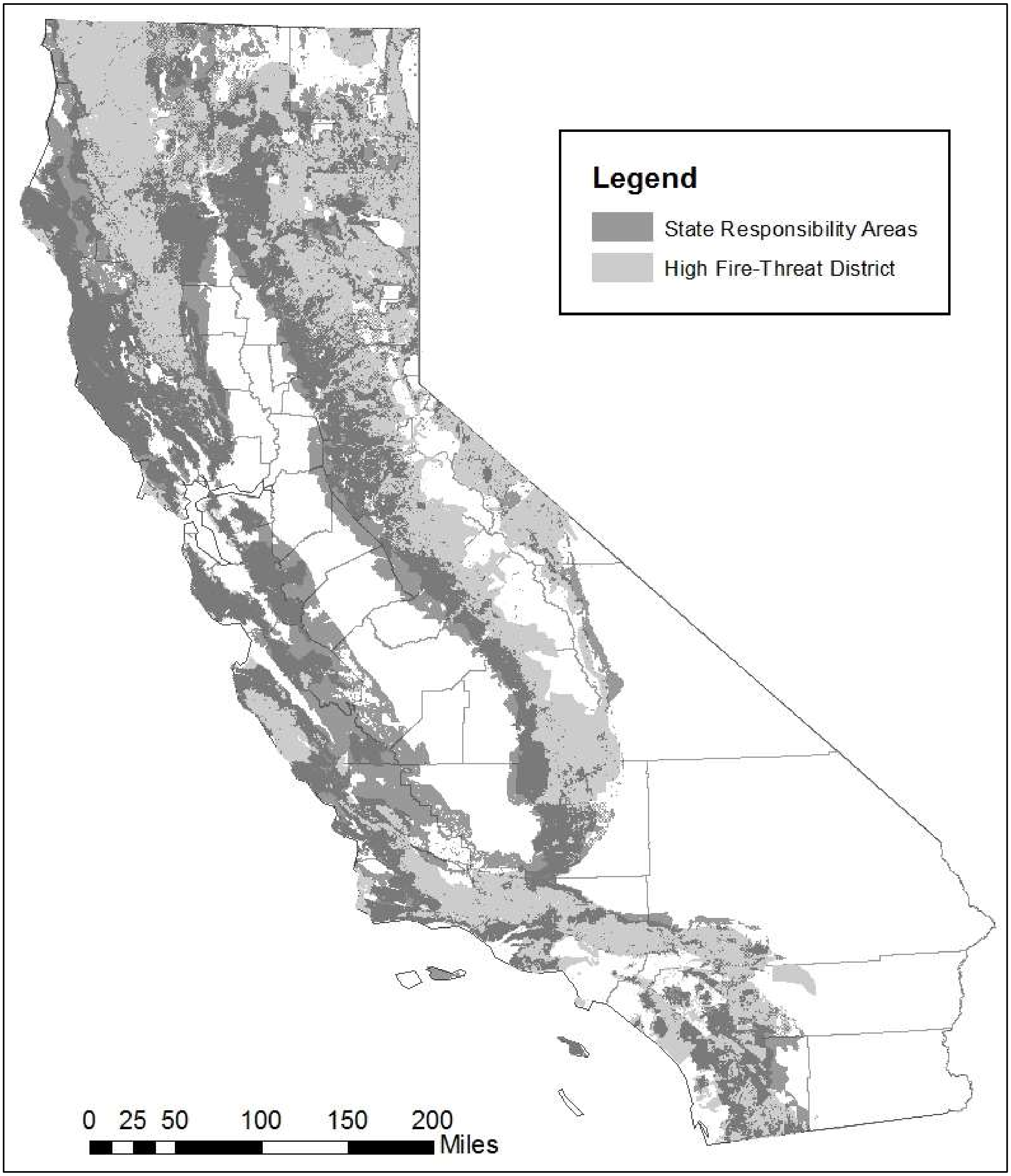
[46] The ten Counties are Amador, Calaveras, El Dorado, Fresno, Kern, Madera, Mariposa, Placer, Tulare and Tuolumne.

[47] Tree Mortality Task Force Meeting Minutes, September 11, 2017, http://www.fire.ca.gov/treetaskforce/downloads/Monthly_MeetingMaterials/TMTF_%20Minutes_9-11-17.pdf. (Accessed October 13, 2017).

[48] The map shows an overlay of SRAs on the draft High Fire-Threat District Map in Appendix D of today's Decision.

**Figure 2**

**Overlay of SRAs on the Draft High Fire-Threat District Map**



Although Case 14 incorporates the vegetation clearances established by Pub. Res. Code § 4293 for SRAs, Case 14 is stricter than Pub. Res. Code § 4293 in the following respects:

- Pub. Res. Code § 4293 does not establish a clearance requirement for power lines with voltages in the range of 0.75-2.4 kV. In contrast, Case 14 requires a minimum vegetation clearance of 18 inches for such power lines.
- Pub. Res. Code § 4293 establishes a minimum vegetation clearance of 10 feet for power lines with voltages greater than 500 kV. In contrast, Case 14 requires a minimum clearance of 10 feet plus 0.40 inches for every kV in excess of 500 kV.
- The vegetation clearances established by Pub. Res. Code § 4293 apply only during the fire season declared by CAL FIRE for each county. In contrast, Case 14 applies year-round.
- Pub. Res. Code § 4293 applies to power lines in SRAs that are located on mountainous land, forest-covered land, brush-covered land, or grassland. In contrast, Case 14 applies to power lines everywhere in the high fire-threat areas designated by the Commission.

We disagree with TURN that Case 14 vegetation clearances should not be extended to any part of the High Fire-Threat District at this time due to insufficient information to assess the costs and benefits. If TURN were to have its way, Case 14 would continue to apply only to high fire-threat areas in Southern California on the Interim Fire-Threat Maps, including areas that are not in the High Fire-Threat District. We believe it is imprudent to require electric utilities to spend money and effort to maintain Case 14 vegetation clearances in areas outside the High Fire-Threat District.

Moreover, it would be reckless to exempt the entire High Fire-Threat District from the Case 14 vegetation clearances. Power-line fires can cause enormous destruction as demonstrated by the catastrophic power-line fires in

Southern California in October 2007[49] and the devastating Butte Fire in Amador and Calaveras Counties in September 2015.[50] The catastrophic wildfires in Northern California in October 2017 further demonstrate the enormous destruction and loss of life that wildfires can cause.[51] In our judgement, the Case 14 vegetation clearances are a reasonable measure for preventing catastrophic power-line fires in the High Fire-Threat District, as demonstrated by the fact that such clearances have been in effect for many years in SRAs.[52]

We disagree with PacifiCorp that extending Case 14 vegetation clearances to the High Fire-Threat District statewide is not cost-effective, practical, or necessary. The previous maps show that (1) the region where PacifiCorp's service territory is located is prone to large wildfires in the High Fire-Threat District, and (2) PacifiCorp's service territory includes SRAs where PacifiCorp is already required to maintain Case 14 vegetation clearances for much of the year.

#### 4.2.7. Proposed Regulation 8 re: GO 95, Rule 38

#### 4.2.7.1 Summary of Proposal

Rule 38 of GO 95 specifies minimum radial clearances between wires. Currently, Rule 38 allows a 10 percent reduction of the minimum clearances in certain circumstances.

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[49] The October 2007 power-line wildfires in Southern California burned more than 334 square miles.

[50] The Butte Fire of September 2015, located within Tier 2, burned more than 70,000 acres (106 square miles), destroyed an estimated 921 structures, and resulted in two fatalities.

[51] The Northern California wildfires are cited for the sole purposes of demonstrating the enormous destructive potential of wildfires. The cause of the Northern California wildfires is currently under investigation.

[52] We do not believe it is in the public interest for the wildfire prevention afforded by the Case 14 vegetation clearances to apply to SRAs, but not to the High Fire-Threat District where there is an elevated or extreme risk for utility-associated wildfires.

### 4.2.17. Proposed Regulation 19 re: GO 95, Appendix E

#### 4.2.17.1 Summary of Proposal

In Section 4.2.6 of today's Decision, we amend GO 95, Rule 35, Table 1, Case 14 to specify minimum radial clearances between bare line conductors and vegetation throughout the High Fire-Threat District.

Appendix E of GO 95 ("Appendix E") specifies recommended clearances to be obtained between bare line conductors and vegetation at the time vegetation is trimmed ("time-of-trim clearances"). One purpose of Appendix E's recommended time-of-trim clearances is to ensure that there is no breach of the minimum clearances required by Case 14 during the period between trims.

SDG&E's PR 19 proposes to amend Appendix E to increase the recommended time-of-trim clearances applicable to Case 14. The following table lists the current and proposed recommended time-of-trim clearances:

**Table 14**
**GO 95, Appendix E**
**Recommended Time-of-Trim Clearance for GO 95, Rule 35, Table 1, Case 14**
**High Fire-Threat District**

| Voltage of Line | Current | Proposed by PR 19 |
|---|---|---|
| Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volts | 6.5 feet | 12 feet |
| Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 volts | 10 feet | 20 feet |
| Radial clearances for any conductor of a line operating at 110,000 or more volts, but less than 300,000 volts | 20 feet | 30 feet |
| Radial clearances for any conductor of a line operating at 300,000 or more volts | 20 feet | 30 feet |

The text of SDG&E's proposed revisions to Appendix E of GO 95 is set forth in Appendix A of today's Decision. SDG&E recommends that PR 19 take

effect 12 months after the Commission's adoption of a High Fire-Threat District Map. SDG&E did not provide a cost estimate for PR 19, but expects that any cost impacts on CIPs and electric utilities will be negligible.

#### 4.2.17.2 Positions of the Parties

SDG&E submits that PR 19 will enhance safety by increasing the distance between trees and power lines at the time-of-trim. It will also reduce the time and money needed to maintain the vegetation clearances of Case 14, since utilities would not need to trim trees as frequently.

IBEW 1245, PG&E, and SCE support PR 19 because they believe it will enable utilities to obtain a greater safety margin for conductor-vegetation clearances in the High Fire-Threat District.

Most parties are neutral with respect to PR 19, including a majority of the CIP parties, Bear Valley, Laguna Beach, LACFD, Liberty Utilities, MGRA, PacifiCorp, and SED.

The Joint POUs and TURN oppose PR 19, arguing that SDG&E's claim that the costs of PR 19 will be negligible is not supported by facts in the record. The Joint POUs raise an additional concern that a one-size-fits-all approach to increasing vegetation clearances throughout the High Fire-Threat District creates a standard that may be impossible to meet, particularly in situations where the utility lacks sufficient property rights to expand its vegetation clearing.

#### 4.2.17.3 Discussion

The issue before us is whether to adopt PR 19. Our standard for deciding this issue is whether PR 19 will enhance fire safety in the High Fire-Threat District at a reasonable cost.

We agree with SDG&E that adopting PR 19 will help electric utilities to maintain safe clearances between vegetation and power lines in the High Fire-

Threat District. We do not anticipate that adopting PR 19 will increase tree maintenance costs substantially. As SDG&E suggests, PR 19 could reduce the frequency of trimming that is necessary to comply with the Case 14 minimum clearances and thereby reduce vegetation management costs. But to the extent that costs do increase, we conclude that such costs are offset by the substantial public-safety benefits of keeping bare line conductors clear of vegetation in the High Fire-Threat District, which our adoption of PR 19 will help to facilitate.

For the preceding reasons, we conclude that it is in the public interest to adopt PR 19. We acknowledge the Joint POUs' concern that the increased recommended time-of-trim clearances adopted by today's Decision for the High Fire-Threat District may be impossible to meet in some cases. We note that Appendix E does not require electric utilities to achieve compliance when it is impossible to do so. Rather, it states that recommended clearances "**should be established**, at time of trimming, between the vegetation and the energized conductors and associated live parts **where practicable**." (Emphasis added.)

#### 4.2.18. Proposed Regulation 20, Alternative Proposed Regulation 20/AP-1, and Alternative Proposed Regulation 20/AP-2 re: GO 165, Table 1

##### 4.2.18.1 Summary of Proposals

Table 1 of GO 165 ("GO 165") requires electric utilities to conduct a patrol inspection of their overhead electric utility distribution facilities every two years in rural areas,[81] and every year in rural areas of Southern California that are also

[81] GO 165 defines "rural" as "those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census."

high fire-threat areas on the Interim Fire-Threat Maps. There are three proposals to revise GO 165. Each proposal is summarized below.

**PR 20 (FSTP)**

The FSTP's PR 20 would amend GO 165 to replace references to the Interim Fire-Threat Maps with references to Tier 3 of the High Fire-Threat District. The effect of PR 20 is to require an annual patrol inspection of overhead electric utility distribution facilities in rural areas in Southern California that are also Tier 3 fire-threat areas of the High Fire-Threat District.

The text of the FSTP's proposed amendments to GO 165 is contained in Appendix A of today's Decision. The FSTP recommends that PR 20 take effect 12 months after the Commission's adoption of the High Fire-Threat District Map. The FSTP did not provide a cost estimate for implementing PR 20 because the High Fire-Threat District Map is not yet complete.

**PR 20/AP-1 (SED)**

SED's PR 20/AP-1 would amend GO 165 to require an annual patrol inspection of overhead electric utility distribution facilities located in rural areas of Tier 2 and Tier 3 of the High Fire-Threat District statewide.

The text of SED's proposed amendments to GO 165 is contained in Appendix A of today's Decision. SED recommends that PR 20/AP-1 take effect 12 months after the Commission's adoption of the High Fire-Threat District Map. SED did not provide an estimate of the costs that electric utilities would incur to implement PR 20/AP-1. Nonetheless, SED believes that the costs would be far outweighed by the public-safety benefits of reducing the risk of catastrophic utility-associated wildfires in areas where there is an elevated risk (Tier 2) or extreme risk (Tier 3) for such wildfires.

**PR 20/AP-2 (PacifiCorp)**

PacifiCorp's PR 20/AP-2 would amend GO 165 to require an annual patrol inspection of overhead electric utility distribution facilities located in rural areas of Tier 3 of the High Fire-Threat District statewide (but not Tier 2 statewide).

The text of PacifiCorp's proposed amendments to GO 165 is contained in Appendix A of today's Decision. PacifiCorp recommends PR 20/AP-2 take effect on January 1 of the next full calendar year after the rule is adopted. PacifiCorp estimates that for its own service territory, PR 20/AP-2 would increase its inspection costs by approximately $16,000 to $20,000 per year. PacifiCorp did not provide a cost estimate for other service territories.

#### 4.2.18.2 Positions of the Parties

**PR 20**

The FSTP submitted PR 20 to implement the requirement established by D.17-01-009 to transfer existing fire-safety regulations that apply only to high fire-threat areas on the Interim Fire-Threat Maps to corresponding Tier 3 fire-threat areas of the High Fire-Threat District. The FSTP adds that PR 20 is in the public interest because it will continue the requirement to conduct an annual patrol inspection of overhead electric utility distribution facilities in rural high fire-threat areas of Southern California.

PR 20 is supported by Bear Valley, IBEW 1245, Liberty Utilities, PacifiCorp, PG&E, and SCE. Most supporters have little to say about PR 20. Liberty Utilities, the most loquacious of the supporters, states that PR 20 is not cost-prohibitive and protects fire safety in the most fire-prone areas of the State.

The following parties take a neutral position regarding PR 20: Most of the CIP parties, the Joint POUs, Laguna Beach, MGRA, and SDG&E.

PR 20 is opposed by LACFD, SED, and TURN. LACFD did not submit written comments. SED states that PR 20 does not adequately protect public safety because the proposed regulation applies only to Tier 3 fire-threat areas in Southern California. SED recommends much broader geographic coverage in SED's PR 20/AP-1.

TURN argues there is insufficient information to assess whether the costs that utilities will incur to implement PR 20 are reasonable. TURN states that under California law, all utility spending must be justified under Pub. Util. Code § 454(a) and meet the just and reasonable standard of § 451. TURN claims that PR 20 does not meet these statutory requirements because the FSTP did not provide a cost estimate or cost-benefit analysis for PR 20.

**PR 20/AP-1**

SED submits that PR 20/AP-1 will enhance fire safety because the proposed rule will ensure that overhead electric utility distribution facilities located in rural areas where there is elevated risk (Tier 2) or extreme risk (Tier 3) for utility-related wildfires are inspected annually.

PR 20/AP-1 is supported by LACFD and IBEW 1245. LACFD did not submit written comments. IBEW 1245 opines that SED's justification for increased patrol inspections is compelling.[82]

The following parties take a neutral position regarding PR 20/AP-1: Most of the CIP parties, the Joint POUs, Laguna Beach, MGRA, and SDG&E.

The following parties oppose PR 20/AP-1: Bear Valley, Liberty Utilities, PG&E, PacifiCorp, SCE, and TURN. The Electric IOU opponents note that

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[82] The Workshop Report mistakenly placed IBEW 1245's comments in support of SED's PR 20/AP-1 in the section of the Report that contains comments in support of the PR 20.

GO 165 currently requires biennial patrol inspections of overhead electric utility distribution facilities in rural areas statewide. They contend that requiring annual patrol inspections in Tier 2 fire-threat areas statewide, as recommend by SED in PR 20/AP-1, would increase their inspection costs significantly with little benefit to public safety. On the other hand, these same opponents do not object to annual patrol inspections in rural Tier 3 fire-threat areas statewide as recommend by PacifiCorp in PR 20/AP-2.

TURN contends that utility expenditures for fire safety must be supported by the record, justified, and reasonable pursuant to Pub. Util. Code §§ 451 and 454(a). TURN notes that the proponent of PR 20/AP-1, SED, did not provide a cost-benefit analysis for this proposed regulation.

TURN believes that PR 20/AP-1 could significantly increase costs for ratepayers because the proposed rule would vastly expand the geographic area where annual patrol inspections are required. TURN recommends that because of the potentially significant costs, and the lack of a cost-benefit analysis, the Commission should not adopt PR 20/AP-1 at this time.

**PR 20/AP-2**

PacifiCorp avers that although its PR 20/AP-2 may increase costs for ratepayers, the cost-benefit outcome is favorable. PacifiCorp states that PR 20/AP-2 will enable ratepayer funds to be used efficiently to target fire-safety efforts in the geographic areas of the State most at risk for utility-caused fire damage, *i.e.*, in Tier 3 fire-threat areas. PacifiCorp adds that PR 20/AP-2 balances the public interest in reducing fire hazards in the areas of greatest risk without unduly burdening ratepayers with the cost of deploying additional patrol inspections more widely across the State.

PR 20/AP-2 is supported by Bear Valley, PG&E, and SCE. In general, the supporters agree with PacifiCorp that it is reasonable to focus patrol inspections on Tier 3 fire-threat areas.

The following parties take a neutral position regarding PR 20/AP-2: Most of the CIP parties, the Joint POUs, IBEW 1245, Laguna Beach, Liberty Utilities, MGRA, and SDG&E. Liberty Utilities, the only neutral party to offer comments on PR 20/AP-2, states that although it generally supports the proposed regulation, it is not possible to determine how costly or feasible the regulation will be in Liberty Utilities' service territory until the map for Tier 3 is finalized. Until then, Liberty Utilities withholds its support.

PR 20/AP-2 is opposed by LACFD, SED, and TURN. LACFD did not comment on this matter. SED comments that although expanding the annual patrol inspection requirement to rural Tier 3 areas statewide is a necessary step, it is not sufficient. SED asserts that the annual patrol inspection requirement should apply to rural Tier 2 areas statewide, too, as recommended by SED in PR 20/AP-1. TURN asserts that there is insufficient information to determine if PR 20/AP-2 is cost-effective or reasonable.

#### 4.2.18.3 Discussion

The issue before us is whether to adopt PR 20, PR 20/AP-1, or PR 20/AP-2, or some combination thereof. Our objective is to select the option that best enhances fire safety in the High Fire-Threat District at a reasonable cost.

For the reasons set forth below, we conclude that it is in the public interest to adopt SED's PR 20/AP-1. This has the effect of amending GO 165 to require electric utilities to conduct an annual patrol inspection of their overhead electric utility distribution facilities in rural Tier 2 and Tier 3 fire-threat areas statewide.

Overhead electric utility distributions facilities pose an ever-present hazard for ignitions. It is essential that such facilities be maintained in good condition to mitigate the risk of utility-associated wildfires.[83] Extra vigilance in the form of annual patrol inspections is warranted in rural Tier 2 and Tier 3 fire-threat areas, where there is an elevated or extreme risk for utility-associated wildfires, to ensure that overhead electric utility distribution facilities in such areas are maintained in good condition.

We recognize that today's Decision significantly expands the geographic area that is subject to GO 165's annual patrol inspection requirement, which will undoubtedly increase inspection costs for electric utilities. However, we conclude the costs will not be unduly burdensome for the following reasons. First, the scope of a patrol inspection is limited. GO 165 defines a patrol inspection as:

> **"Patrol inspection"** shall be defined as a simple visual inspection, of applicable utility equipment and structures, that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business. (Bold highlight in GO 165.)

Because of the limited scope of patrol inspections, the cost of conducting a patrol inspection is modest. SDG&E estimates the cost is approximately $3.00 per facility, including labor time, salary of the employee, and vehicle/fuel costs.[84]

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83 *See*, e.g., SDG&E Comments (July 31, 2017) at 2: "Fire ignition risk can be reduced by adequately maintaining overhead facilities in the High Fire-Threat District. Equipment failures and consequent risks of ignition sources) may be avoided by timely inspection, and appropriate maintenance cycles/methods."

84 Workshop Report at B-156.

Second, California has an estimated 4.2 million utility poles,[85] which suggests that the incremental statewide cost of the patrol inspection cycle adopted by today's Decision will be in the range of $12.6 million annually ($3.00 per pole x 4.2 million). However, GO 165 already requires an annual patrol inspection of overhead electric utility distribution facilities located in urban areas[86] where the majority of overhead electric utility distribution infrastructure is concentrated.[87] This suggests that the statewide incremental cost of the patrol inspection requirement adopted by today's Decision (which applies to rural areas in Tier 2 and Tier 3) may be less than $12.6 million annually.

Third, Electric IOUs currently recover in rates the just and reasonable costs they incur to conduct annual patrol inspections of overhead electric utility distribution facilities in urban areas mandated by GO 165. We conclude that the costs of annual patrol inspections in rural Tier 2 and Tier 3 fire-threat areas is equally just and reasonable (following Commission review and approval).

Finally, we find that the cost of the annual patrol inspection requirement adopted by today's Decision is offset by the substantial public-safety benefits[88] that the annual inspections provide by reducing the risk of utility-associated wildfires occurring in Tier 2 (elevated) and Tier 3 (extreme) fire-threat areas, such

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85 Combined Order Instituting Investigation 17-06-027 and Order Instituting Rulemaking 17-06-028 at 2. ("OII 17-06-027/OIR 17-06-028").

86 GO 165 defines "urban" as "those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census."

87 Prior to today's Decision, GO 165 required an annual patrol inspection of overhead electric distribution facilities in rural high fire-threat areas of Southern California on the Interim Fire-Threat Maps. Today's Decision should cause little or no increase in the cost of patrol inspections for most or all facilities.

88 OII 17-06-027/OIR 17-06-028 at 8-12 discusses pole safety.

as the catastrophic power-line fires of October 2007. The Commission and ratepayers are still dealing with the cost of these wildfires today.[89]

The provisions of GO 165 that are amended by today's Decision are set forth in Appendix B of today's Decision.

#### 4.2.19. Proposed Regulation 21 and Alternative Proposed Regulation 21/AP-1 re: GO 166, Standard 1, Part E

#### 4.2.19.1 Summary of Proposals

GO 166, Standard 1, Part E, requires those Electric IOUs identified below to prepare a fire-prevention plan that:

> A. Lists and describes the measures the electric utility intends to implement, both in the short run and in the long run, to mitigate the threat of power-line fires generally and in the specific situation where all three of the following conditions occur simultaneously: (i) The force of 3-second wind gusts exceeds the structural or mechanical design standards for the affected overhead power-line facilities, (ii) these 3-second gusts occur during a period of high fire danger, and (iii) the affected facilities are located in a high fire-threat area. A utility's fire-prevention plan may address other situations than required by this GO 166, but not in lieu of GO 166.
>
> B. Identifies the specific parts of the electric utility's service territory where all three of the fire-weather conditions listed in Item A, above, may occur simultaneously. In making this determination, the utility shall use a minimum probability of 3% over a 50-year period that 3-second wind gusts which exceed

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[89] *See*, for example, Application 15-09-010 wherein SDG&E seeks authority to recover from its ratepayers $379 million of uninsured costs stemming from the October 2007 wildfires. The $379 million represents a fraction of the $2.4 billion in total costs and legal fees incurred by SDG&E to resolve third-party damage claims arising from the October 2007 wildfires.

# Appendix B: Adopted Revisions to General Orders 95, 165, and 166, and Electric Tariff Rule 11

Appendix B shows the revised parts of General Orders 95, 165, and 166, and Electric Tariff Rule 11 adopted by this Decision.

**General Order 95, Rule 18**

**Adopted Rule in Final Form**

**18 Reporting and Resolution of Safety Hazards Discovered by Utilities**

For purposes of this rule, "Safety Hazard" means a condition that poses a significant threat to human life or property.

**A. Resolution of Safety Hazards and General Order Nonconformances**

(1)(a) Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 nonconformances posed by its facilities.

(b) Upon completion of the corrective action, the company's records shall show, with sufficient detail, the nature of the work, the date, and the identity of persons performing the work. These records shall be preserved by the company for at least ten (10) years and shall be made available to Commission staff upon 30 days' notice.

(c) Where a communications company's or an electric utility' actions result in GO nonconformances for another entity, that entity's remedial action will be to transmit a single documented notice of identified nonconformances to the communications company or electric utility for compliance.

(2)(a) All companies shall establish an auditable maintenance program for their facilities and lines. All companies must include a timeline for corrective actions to be taken following the identification of a Safety Hazard or nonconformances with General Order 95 on the company's facilities. The auditable maintenance program shall prioritize corrective actions consistent with the priority levels set forth below and based on the following factors, as appropriate:

- Safety and reliability as specified in the priority levels below;
- Type of facility or equipment;
- Location, including whether the Safety Hazard or nonconformance is located in the High Fire-Threat District;
- Accessibility;
- Climate;
- Direct or potential impact on operations, customers, electrical company

There shall be 3 priority levels.

(i) Level 1:

- Immediate safety and/or reliability risk with high probability for significant impact.
- Take action immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

(ii) Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority). Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed: (1) six months for nonconformances that create a fire risk located in Tier 3 of the High Fire-Threat District; (2) 12 months for nonconformances that create a fire risk located in Tier 2 of the High Fire-Threat District; (3) 12 months for nonconformances that compromise worker safety; and (4) 59 months for all other Level 2 nonconformances.

(iii) Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) as appropriate.

(b) Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)

(3) Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18A shall continue to follow their General Order 165 programs.

## General Order 95, Rule 35, Table 1, Case 14 and Reference (hhh)

## Adopted Rule in Final Form

| Case No. | Nature of Clearance | Table 1<br>Wire or Conductor Concerned | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | A<br>Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers | B<br>Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts | C<br>Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts | D<br>Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8 | E<br>Supply Conductors and Supply Cables, 750 - 22,500 Volts | F<br>Supply Conductors and Supply Cables, 22.5 - 300 kV | G<br>Supply Conductors and Supply Cables, 300 - 550 kV (mm) |
| 14 | Radial clearance of bare line conductors from vegetation in the High Fire-Threat District (hhh) (aaa) (ddd) (jjj) | | | 18 inches (bbb) | | 48 inches (bbb) (iii) | 48 inches (fff) | 120 inches (ggg) |

**References to Rules Modifying Minimum Clearances in Table 1**

(hhh) The High Fire-Threat District is defined in GO 95, Rule 21.2-D.

**General Order 95, Appendix E**

**Adopted Rule in Final Form**

## Appendix E – Guidelines to Rule 35

The following are guidelines to Rule 35.

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances than those listed below to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, fire risk, and vegetation trimming requirements that are applicable to State Responsibility Area lands pursuant to Public Resource Code Sections 4102 and 4293.

| Voltage of Lines | Case 13 of Table 1 | Case 14 of Table 1 |
|---|---|---|
| Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volt | 4 feet | 12 feet |
| Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 volts | 6 feet | 20 feet |
| Radial clearances for any conductor of a line operating at 110,000 or more volts but less than 300,000 volts | 10 feet | 30 feet |
| Radial clearance for any conductor of a line operating at 300,000 or more volts | 15 feet | 30-feet |

Note: Added November 6, 1992, by Resolution SU-15 and revised September 20, 1996, by Decision No. 96-09-097, August 20, 2009 by Decision No. 09-08-029 and January 12, 2012 by Decision No. 12-01-032.

## General Order 165, Table 1, Footnote 1

**Adopted Amendment in Final Form**

**Table 1 Distribution Inspection Cycles (Maximum Intervals in Years)**

| | Patrol | | Detailed | | Intrusive | |
|---|---|---|---|---|---|---|
| | Urban | Rural | Urban | Rural | Urban | Rural |
| **Transformers** | | | | | | |
| Overhead | 1 | 2[1] | 5 | 5 | --- | --- |
| Underground | 1 | 2 | 3 | 3 | --- | --- |
| Padmounted | 1 | 2 | 5 | 5 | --- | --- |
| **Switching/Protective Devices** | | | | | | |
| Overhead | 1 | 2[1] | 5 | 5 | --- | --- |
| Underground | 1 | 2 | 3 | 3 | --- | --- |
| Padmounted | 1 | 2 | 5 | 5 | --- | --- |
| **Regulators/Capacitors** | | | | | | |
| Overhead | 1 | 2[1] | 5 | 5 | --- | --- |
| Underground | 1 | 2 | 3 | 3 | --- | --- |
| Padmounted | 1 | 2 | 5 | 5 | --- | --- |
| | | | | | | |
| Overhead Conductor and Cables | 1 | 2[1] | 5 | 5 | --- | --- |
| Streetlighting | 1 | 2 | x | x | --- | --- |
| Wood Poles under 15 years | 1 | 2 | x | x | --- | --- |
| Wood Poles over 15 years which have not been subject to intrusive inspection | 1 | 2 | x | x | 10 | 10 |
| Wood poles which passed intrusive inspection | --- | --- | --- | --- | 20 | 20 |

(1) Patrol inspections in rural areas shall be increased to once per year in Tier 2 and Tier 3 of the High Fire-Threat District. (See GO 95, Rule 21.2-D.)

The amendments to GO 165 adopted by today's Decision do not affect several notes following the above text in Footnote 1.

# Exhibit 28

STATE OF CALIFORNIA

# RULES

FOR

# Overhead Electric Line Construction

Prescribed by the

PUBLIC UTILITIES COMMISSION

OF THE

**STATE OF CALIFORNIA**

GENERAL ORDER No. 95

**May 2018**

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**(1) Definition of major accidents and failures:**

**(a)** Incidents associated with utility facilities which cause property damage estimated at or about the time of the incident to be more than $50,000.

**(b)** Incidents resulting from electrical contact which cause personal injury which require hospitalization overnight, or result in death.

**EXCEPTION:** Does not apply to motor vehicle caused incidents.

Note: Added January 13, 2005 by Decision No. 0501030.

## 18 Maintenance Programs and Resolution of Potential Violations of General Order 95 and Safety Hazards

For purposes of this rule, "Safety Hazard" means a condition that poses a significant threat to human life or property.

### A Resolution of Potential Violations of General Order 95 and Safety Hazards

(1) Each company (including electric utilities and communications companies) is responsible for taking appropriate corrective action to remedy potential violations of GO 95 and Safety Hazards posed by its facilities.

Upon completion of the corrective action, the company's records shall show, with sufficient detail, the nature of the work, the date, and the identity of persons performing the work. These records shall be preserved by the company for at least ten (10) years.

(2) Where a communications company's or an electric utility's (Company A's) actions result in potential violations of GO 95 for another entity (Company B), that entity's (Company B's) remedial action will be to transmit a single documented notice of identified potential violations to the communications company or electric utility (Company A) within a reasonable amount of time not to exceed 180 days after the entity discovers the potential violations of GO 95. If the potential violation constitutes a Safety Hazard, such notice shall be transmitted within ten (10) business days after the entity discovers the Safety Hazard.

(3) If a company, while performing inspections of its facilities, discovers a Safety Hazard(s) on or near a communications facility or electric facility involving another company, the inspecting company shall notify the other entity of such Safety Hazard(s) no later than ten (10) business days after the discovery.

(4) To the extent a company that has a notification requirement under (2) or (3) above cannot determine the facility owner/operator, it shall contact the pole owner(s) within ten (10) business days if the subject of the notification is a Safety Hazard, or otherwise within a reasonable amount of time not to exceed 180 days after discovery. The notified pole owner(s) shall be responsible for promptly (normally not to exceed five business days) notifying the company owning/operating the facility if the subject of the notification is a Safety Hazard, or otherwise within a reasonable amount of time not to exceed 180 days, after being notified of the potential violation of GO 95.

(5) A company receiving a notification under (2), (3), or (4) above shall take appropriate corrective action consistent with the provisions of this rule. For at least ten (10) years, the documentation of the notice shall be maintained by both the notifying and receiving parties and documentation of the correction shall be maintained by the receiving party.

Note: Each pole owner must be able to determine all other pole owners on poles it owns. Each pole owner must be able to determine all authorized entities that attach equipment on its portion of a pole.

## B Maintenance Programs

Each company (including electric utilities and communications companies) shall establish and implement an auditable maintenance program for its facilities and lines for the purpose of ensuring that they are in good condition so as to conform to these rules. Each company must describe in its auditable maintenance program the required qualifications for the company representatives who perform inspections and/or who schedule corrective actions. Companies that are subject to GO 165 may maintain procedures for conducting inspections and maintenance activities in compliance with this rule and with GO 165.

The auditable maintenance program must include, at a minimum, records that show the date of the inspection, type of equipment/facility inspected, findings, and a timeline for corrective actions to be taken following the identification of a potential violation of GO 95 or a Safety Hazard on the company's facilities.

(1) Companies shall undertake corrective actions within the time periods stated for each of the priority levels set forth below.

Scheduling of corrective actions within the time periods below may be based on additional factors, including the following factors, as appropriate:

- Type of facility or equipment;
- Location, including whether the Safety Hazard or potential violation is located in the High Fire-Threat District;
- Accessibility;
- Climate;
- Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public.

(a) The maximum time periods for corrective actions associated with potential violation of GO 95 or a Safety Hazard are based on the following priority levels:

(i) Level 1 -- An immediate risk of high potential impact to safety or reliability:

- Take corrective action immediately, either by fully repairing or by temporarily repairing and reclassifying to a lower priority.

(ii) Level 2 -- Any other risk of at least moderate potential impact to safety or reliability:

- Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority). Time period for corrective action to be determined at the time of identification by a qualified company representative, but not to exceed: (1) six months for potential violations that create a fire risk located in Tier 3 of the High Fire-Threat District; (2) 12 months for potential violations that create a fire risk located in Tier 2 of the High Fire-Threat District; (3) 12 months for potential violations that compromise worker safety; and (4) 36 months for all other Level 2 potential violations.

(iii) Level 3 -- Any risk of low potential impact to safety or reliability:

- Take corrective action within 60 months subject to the exception specified below.

- Take corrective action within 60 months subject to the exception specified below.

  EXCEPTION – Potential violations specified in Appendix J or subsequently approved through Commission processes, including, but not limited to, a Tier 2 Advice Letter under GO 96B, that can be completed at a future time as opportunity-based maintenance.

  Where an exception has been granted, repair of a potential violation must be completed the next time the company's crew is at the structure to perform tasks at the same or higher work level, i.e., the public, communications, or electric level. The condition's record in the auditable maintenance program must indicate the relevant exception and the date of the corrective action.

Note: Appendix I contains illustrative examples of potential violations of GO 95 and Safety Hazards, and their priority levels used to determine the maximum time period for corrective action.

(b) Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)

(2) Commission staff may direct a company to correct violation(s) of GO 95 at specific location(s) sooner than the maximum time periods contained in this rule.

Note: Added August 20, 2009 by Decision No. 09-08-029. Revised January 12, 2012 by Decision No. 1201032, December 14, 2017 by Decision No.17-12-024 (corrected by D.18-02-001), and May 31, 2018, by Decision No.18-05-042 (implementation date for the amendments to Rule 18 adopted in this D.18-05-042 is June 30 2019).

### F. Energized Conductor (Wire or Cable)

All energized conductor (wire or cable) shall be covered with an insulation suitable for the voltage involved (See Rule 20.9–G).

### G. Guying

Where mechanical loads imposed on poles or structures exceed safety factors as specified in Rule 44, or at the request of the granting authority, additional strength shall be provided by the use of guys or other suitable construction. When guying is required, refer to Rules 56 and 86 for applicable requirements.

Note: Revised November 6,1992 by Resolution No. SU–15.

## 35 Vegetation Management

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances, the minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions shall be maintained. (Also see Appendix E for tree trimming guidelines.) These requirements apply to all overhead electrical supply and communication facilities that are covered by this General Order, including facilities on lands owned and maintained by California state and local agencies.

When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that dead, rotten or diseased trees or dead, rotten or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of supply or communication lines, said trees or portions thereof should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that its circuit energized at 750 volts or less shows strain or evidences abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension, rearranging or replacing the conductor, pruning the vegetation, or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the vegetation and conductor. Scuffing or polishing of the insulation or covering is not considered abrasion. Strain on a conductor is present when vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors, in and of itself, does not constitute a nonconformance with the rule.

**EXCEPTIONS:**

**1.** Rule 35 requirements do not apply to conductors, or aerial cable that complies with Rule 57.4-C, energized at less than 60,000 volts, where trimming or removal is not practicable and the conductor is separated from the tree with suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.

**2.** Rule 35 requirements do not apply where the utility has made a "good faith" effort to obtain permission to trim or remove vegetation but permission was refused or unobtainable. A "good faith" effort shall consist of current documentation of a minimum of an attempted personal contact and a written communication, including documentation of mailing or delivery. However, this does not preclude other action or actions from demonstrating "good faith". If permission to trim or remove vegetation is unobtainable and requirements of exception 2 are met, the utility is not compelled to comply with the requirements of exception 1.

**3.** The Commission recognizes that unusual circumstances beyond the control of the utility may result in nonconformance with the rules. In such cases, the utility may be directed by the Commission to take prompt remedial action to come into conformance, whether or not the nonconformance gives rise to penalties or is alleged to fall within permitted exceptions or phase–in requirements.

Note: Revised November 6,1992 by Resolution No. SU–15, September 20, 1996 by Decision No. 96–09–097, January 23, 1997 by Decision No. 97–01–044 and January 13, 2005 by Decision No. 0501030..

**4.** Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six–inch minimum clearance under reasonably foreseeable local wind and weather conditions. The utility shall bear the risk of determining whether this exemption applies, and the Commission shall have final authority to determine whether the exemption applies in any specific instance, and to order that corrective action be taken in accordance with this rule, if it determines that the exemption does not apply.

Note: Added October 22, 1997 by Decision No. 97–10–056. Revised August 20, 2009 by Decision No. 09-08-029 and January 12, 2012 by Decision No. 1201032

## 36 Pole Clearances from Railroad Tracks

Poles or other supporting structures which are set in proximity to railroad tracks shall be so located that the clearance requirements of General Order 26–D are met. The clearance requirements of General Order 26–D, applicable to pole line construction, are contained in Appendix E.

Note: Revised February 1, 1948 by Supplement No. 1 (Decision No. 41134, Case No. 4324).

## 37 Minimum Clearances of Wires above Railroads, Thoroughfares, Buildings, Etc.

Clearances between overhead conductors, guys, messengers or trolley span wires and tops of rails, surfaces of thoroughfares or other generally accessible areas across, along or above which any of the former pass; also the clearances between conductors, guys, messengers or trolley span wires and buildings, poles, structures, or other objects, shall not be less than those set forth in Table 1, at a temperature of 60° F. and no wind.

The clearances specified in Table 1, Case 1, Columns A, B, D, E and F, shall in no case be reduced more than 5% below the tabular values because of temperature and loading as specified in Rule 43, or other conditions. The clearances specified in Table 1, Cases 2 to 6 inclusive, shall in no case be reduced more than 10% below the tabular values because of temperature and loading as specified in Rule 43, or other conditions.

The clearance specified in Table 1, Case 1, Column C (22.5 feet), shall in no case be reduced below the tabular value because of temperature and loading as specified in Rule 43.

The clearances specified in Table 1, Cases 11, 12 and 13, shall in no case be reduced below the tabular values because of temperatures and loading as specified in Rule 43.

Where supply conductors are supported by suspension insulators at crossings over railroads which transport freight cars, the initial clearances shall be sufficient to prevent reduction to clearances less than 95% of the clearances specified in Table 1, Case 1, through the breaking of a conductor in either of the adjoining spans.

Where conductors, dead ends, and metal pins are concerned in any clearance specified in these rules, all clearances of less than 5 inches shall be applicable from surface of conductors (not including tie wires), dead ends, and metal pins, except clearances between surface of crossarm and conductors supported on pins and insulators (referred to in Table 1, Case 9) in which case the minimum clearance specified shall apply between center line of conductor and surface of crossarm or other line structure on which the conductor is supported.

All clearances of 5 inches or more shall be applicable from the center lines of conductors concerned.

When measuring the minimum allowable vertical conductor clearances in a span, the minimum clearance applies to the specific location under the span being measured and not for the entire span.

Note: Modified January 8, 1980 by Decision No. 91186, March 9, 1988 by Resolution E–3076; and November 6, 1992 by Resolution SU–15, September 20, 1996 by Decision 96–09–097, January 23, 1997 by Decision 97–01–044 and January 13, 2005 by Decision No. 0501030.

**Table 1: Basic Minimum Allowable Vertical Clearance of Wires above Railroads, Thoroughfares, Ground or Water Surfaces; Also Clearances from Poles, Buildings, Structures or Other Objects (nn) (Letter References Denote Modifications of Minimum Clearances as Referred to in Notes Following This Table)**

| Case No. | Nature of Clearance | Wire or Conductor Concerned | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | A Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers | B Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts | C Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts | D Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8 | E Supply Conductors and Supply Cables, 750 - 22,500 Volts | F Supply Conductors and Supply Cables, 22.5 - 300 kV | G Supply Conductors and Supply Cables, 300 - 550 kV (mm) |
| 1 | Crossing above tracks of railroads which transport or propose to transport freight cars (maximum height 15 feet, 6 inches) where not operated by overhead contact wires. (a) (b) (c) (d) | 25 Feet | 25 Feet | 22.5 Feet | 25 Feet | 28 Feet | 34 Feet | 34 Feet (kk) |
| 2 | Crossing or paralleling above tracks of railroads operated by overhead trolleys. (b) (c) (d) | 26 Feet (e) | 26 Feet (e) (f) (g) | 22.5 Feet (h) (i) (eee) | 27 Feet (e) (g) | 30 Feet (g) | 34 Feet (g) | 34 Feet (g) (kk) |
| 3 | Crossing or along thoroughfares in urban districts or crossing thoroughfares in rural districts. (c) (d) | 18 Feet (j) (k) (ii) | 18 Feet (j) (l) (m) (ii) (kkk) | 19 Feet (hh) (eee) | 20 Feet (ii) | 25 Feet (o) (ii) | 30 Feet (o) (ii) | 30 Feet (o) (ii) (kk) |
| 4 | Above ground along thoroughfares in rural districts or across other areas capable of being traversed by vehicles or agricultural equipment. | 15 Feet (k) | 15 Feet (m) (n) (p) | 19 Feet (eee) | 19 Feet | 25 Feet (o) | 30 Feet (o) (p) | 30 Feet (o) (kk) |
| 5 | Above ground in areas accessible to pedestrians only | 8 Feet | 10 Feet (m) (q) | 19 Feet (eee) | 12 Feet | 17 Feet | 25 Feet (o) | 25 Feet (o) (kk) |
| 6 | Vertical clearance above walkable surfaces on buildings, (except generating plants or substations) bridges or other structures which do not ordinarily support conductors, whether attached or unattached. | 8 Feet (r) | 8 Feet (r) | 8 Feet | 8 Feet | 12 Feet | 12 Feet | 20 Feet (ll) |
| 6a | Vertical clearance above non–walkable surfaces on buildings, (except generating plants or substations) bridges or other structures, which do not ordinarily support conductors, whether attached or unattached | 2 Feet | 8 Feet (yy) | 8 Feet | 8 Feet (zz) | 8 Feet | 8 Feet | 20 Feet |
| 7 | Horizontal clearance of conductor at rest from buildings (except generating plants and substations), bridges or other structures (upon which men may work) where such conductor is not attached thereto (s) (t) | - | 3 Feet (u) | 3 Feet | 3 Feet (u) (v) | 6 Feet (v) | 6 Feet (v) | 15 Feet (v) |
| 8 | Distance of conductor from center line of pole, whether attached or unattached (w) (x) (y) | - | 15 inches (s) (aa) | 15 inches (aa) (bb) (cc) | 15 inches (o) (aa) (dd) | 15 or 18 inches (o) (dd) (ee) (jj) | 18 inches (dd) (ee) | Not Applicable |
| 9 | Distance of conductor from surface of pole, crossarm or other overhead line structure upon which it is supported, providing it complies with case 8 above (x) | - | 3 inches (aa) (ff) | 3 inches (aa) (cc) (gg) | 3 inches (aa) (dd) (gg) | 3 inches (dd) (gg) (jj) | 1/4 Pin Spacing Shown in Table 2 Case 15 (dd) | 1/2 Pin Spacing Shown in Table 2 Case 15 (dd) |

**Table 1 (Continued)**

| Case No. | Nature of Clearance | A Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers | B Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts | C Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts | D Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8 | E Supply Conductors and Supply Cables, 750 - 22,500 Volts | F Supply Conductors and Supply Cables, 22.5 - 300 kV | G Supply Conductors and Supply Cables, 300 - 550 kV (mm) |
|---|---|---|---|---|---|---|---|---|
| | | Wire or Conductor Concerned | | | | | | |
| 10 | Radial centerline clearance of conductor or cable (unattached) from non-climbable street lighting or traffic signal poles or standards, including mastarms, brackets and lighting fixtures, and from antennas that are not part of the overhead line system. | - | 1 Foot (u) (rr) (ss) | 15 inches (bb) (cc) | 3 Feet (oo) | 6 Feet (pp) | 10 Feet (qq) | 10 Feet (ll) |
| 11 | Water areas not suitable for sailboating (tt) (uu) (ww) (xx) | 15 Feet | 15 Feet | - | 15 Feet | 17 Feet | 25 Feet | 25 Feet (kk) |
| 12 | Water areas suitable for sailboating, surface area of: (tt) (vv) (ww) (xx)<br>(A) Less than 20 acres<br>(B) 20 to 200 acres<br>(C) Over 200 to 2,000 acres<br>(D) Over 2,000 acres | <br><br>18 Feet<br>26 Feet<br>32 Feet<br>38 Feet | <br><br>18 Feet<br>26 Feet<br>32 Feet<br>38 Feet | <br><br>-<br>-<br>- | <br><br>18 Feet<br>26 Feet<br>32 Feet<br>38 Feet | <br><br>20 Feet<br>28 Feet<br>34 Feet<br>40 Feet | <br><br>27 Feet<br>35 Feet<br>41 Feet<br>47 Feet | <br><br>27 Feet (kk)<br>35 Feet (kk)<br>41 Feet (kk)<br>47 Feet (kk) |
| 13 | Radial clearance of bare line conductors from tree branches or foliage (aaa) (ddd) | - | - | 18 inches (bbb) | - | 18 inches (bbb) | 1/4 pin spacing shown in table 2, Case 15 (bbb) (ccc) | 1/2 pin spacing shown in table 2, Case 15 |
| 14 | Radial clearance of bare line conductors from vegetation in the Fire-Threat District (aaa) (ddd) (hhh)(jjj) | | | 18 inches (bbb) | | 48 inches (bbb) (iii) | 48 inches (fff) | 120 inches (ggg) |

**References to Rules Modifying Minimum Clearances in Table 1**

| | | Rule |
|---|---|---|
| (a) | Shall not be reduced more than 5% because of temperature or loading | 37 |
| | 1 Supply lines | 54.4–B1 |
| | 2 Communication lines | 84.4–B1 |
| (b) | Shall be increased for supply conductors on suspension insulators, under certain conditions | 37 |
| (c) | Special clearances are provided for traffic signal equipment | 58.4–C |
| (d) | Special clearances are provided for street lighting equipment | 58.5–B |
| (e) | Based on trolley pole throw of 26 feet. may be reduced where suitably protected | 56.4–B2 |
| | 1 Supply guys | 56.4–B2 |
| | 2 Supply cables and messengers | 57.4–B2 |
| | 3 Communication guys | 86.4–B2 |
| | 4 Communication cables and messengers | 87.4–B2 |
| (f) | May be reduced depending on height of trolley contact conductors | |
| | 1 Supply service drops | 54.8–C5 |
| | 2 Communication service drops | 84.8–D5 |
| (g) | May be reduced and shall be increased depending on trolley throw | |
| | 1 Supply conductors (except service drops) | 54.4–B2 |
| | 2 Communication conductors (except service drops) | 84.4–B2 |
| (h) | May be decreased where freight cars are not transported. | |
| | 1. Trolley contact and feeder conductors. | 74.4-B1 |
| | 2. Trolley span wires | 77.4-A |
| (i) | May be reduced for trolley contact and span wires in subways, tunnels, under bridges and in fenced areas | |
| | 1 Trolley contact conductors | 74.4–E |
| | 2 Trolley span wires | 77.4–B |
| (j) | May be reduced at crossings over private thoroughfares and entrances to private property and over private property | |
| | 1 Supply service drops | 54.8–B2 |
| | 2 Supply guys | 56.4–A |
| | 3 Communication service drops | 84.8–C2 |
| | 4 Communication guys | 86.4–A |
| (k) | May be reduced along thoroughfares where not normally accessible to vehicles | |
| | 1 Supply guys | 56.4–A1 |
| | 2 Communication guys | 86.4–A1 |
| (l) | May be reduced where within 12 feet of curb line of public thoroughfares | |
| | 1 Supply service drops | 54.8–B1 |
| | 2 Communication service drops | 84.8–C1 |
| (m) | May be reduced for railway signal cables under special conditions | 84.4–A4 |

**References to Rules Modifying Minimum Clearances in Table 1**

| | | | Rule |
|---|---|---|---|
| (n) | May be reduced in rural districts | | |
| | 1 | Intentionally left blank | |
| | 2 | Intentionally left blank | |
| | 3 | Communication conductors along roads | 84.4–A2 |
| (o) | May be reduced for transformer, regulator or capacitor leads | | |
| | 1 | Transformer leads | 58.1–B |
| | 2 | Regulator or capacitor leads | 58.1–B |
| (p) | May be reduced across arid or mountainous areas | | |
| | 1 | Supply conductors of more than 22,500 volts | 54.4–A1 |
| | 2 | Communications conductors | 84.4–A1 |
| (q) | Shall be increased or may be reduced under special conditions | | |
| | 1 | Supply service drops | 54.8–B3 |
| | 2 | Intentionally left blank | |
| | 3 | Communications conductors | 84.4–A3 |
| | 4 | Increased for communication service drops on industrial or commercial premises | 84.8–C3a |
| | 5 | Communication service drops on residential premises | 84.8–C3b |
| (r) | May be reduced above roofs of buildings under special conditions | | |
| | 1 | Supply overhead guys | 56.4–G |
| | 2 | Supply service drops | 54.8–B4 |
| | 3 | Communication overhead guys | 86.4–F |
| | 4 | Communication conductors and cables | 84.4–E |
| | 5 | Communication service drops | 84.8–C4 |
| (s) | Also applies at fire escapes, etc. | | |
| | 1 | Supply conductors | 54.4–H1 |
| | 2 | Vertical clearances | 54.8B4a |
| | 3 | Horizontal clearance | 54.8–B4b |
| | 4 | Communication conductors | 84.4–E |
| (t) | Special clearances where attached to buildings, bridges or other structures | | |
| | 1 | Supply conductors of 750 - 22,500 volts | 54.4–H2 |
| | 2 | Trolley contact conductors | 74.4–E |
| | 3 | Communication conductors | 84.4–F |
| (u) | Reduced clearances permitted under special conditions | | |
| | 1 | Supply service drops on industrial or commercial premises | 54.8–B4a |
| | 2 | Supply cables, grounded | 57.4–G |
| | 3 | Communication cables beside buildings, etc. | 84.4–E |
| | 4 | Communication conductors under bridges, etc. | 84.4–F |
| | 5 | Communication service drops | 84.8–C4 |
| | 6 | Communication cables passing nonclimbable street light poles, etc. | 84.4–D4a |
| (v) | May be reduced under special conditions | | |
| | 1 | Supply conductors of 750 - 7,500 volts | 54.4–H1 |
| | 2 | Supply transformer lead and bus wires, where guarded | 58.1 |
| (w) | May be reduced at angles in lines and transposition points | | |
| | 1 | Supply conductors | 54.4–D1 |
| | 2 | Communication conductors | 84.4–D5 |
| (x) | May be reduced for suitably protected lateral or vertical runs | | |
| | 1 | Supply bond wires | 53.4 |
| | 2 | Supply ground wires | 54.6–B |
| | 3 | Supply lateral conductors | 54.6–C |
| | 4 | Supply vertical runs | 54.6–D |
| | 5 | Supply risers | 54.6–E |
| | 6 | Communication ground wires | 84.6–B |
| | 7 | Communication lateral conductors | 84.6–C |
| | 8 | Communication vertical runs | 84.6–D |
| | 9 | Communication risers | 84.6–E |
| (y) | Increased clearances required for certain conductors | | |
| | 1 | Unattached conductors on colinear and crossing lines | 32.3 |
| | 2 | Unattached supply conductors | 54.4–D3 |
| | 3 | Supply service drops on clearance crossarms | 54.8–C2 |
| | 4 | Supply service drops on pole top extensions | 54.8–C3 |
| | 5 | Unattached supply service drops | 54.8–D |
| | 6 | Communication lines, colinear, conflicting or crossing | 84.4–D3 |
| | 7 | Communication conductors passing supply poles and unattached thereto | 84.4–D4 |
| | 8 | Communication service drops on clearance crossarms | 84.8–D2 |
| | 9 | Communication service drops on pole top extensions | 84.8–D3 |
| | 10 | Unattached communication service drops | 84.8–E |
| (z) | Special provisions for police and fire alarm conductors require increased clearances | | 92.2 |
| (aa) | May be reduced under special provisions | | |
| | 1 | Supply conductors of 0 - 750 volts in rack configuration | 54.4–D5 |
| | 2 | Service supply drops from racks | 54.8–F |
| | 3 | Supply cables and messengers attached to poles | 57.4–F |
| | 4 | Communication conductors on communication poles | 84.4–D |
| | 5 | Communication conductors on crossarms | 84.4–D1 |
| | 6 | Communication conductors attached to poles | 84.4–D2 |
| | 7 | Communication service drops attached to poles | 84.8–B |
| | 8 | Communication cables and messengers | 87.4–D |
| | 9 | Supply or communication cables and messengers on jointly used poles | 92.1–B |
| | 10 | Communication open wire on jointly used poles | 92.1–C |
| | 11 | Multiconductor cable with bare neutral | 54.10–B1 |
| (bb) | May be reduced for class t conductors of not more than 750 volts and of the same potential and polarity | | 74.4–D |
| (cc) | Not applicable to trolley span wires | | 77.4–E |
| (dd) | Special clearances for pole–top and deadend construction | | |
| | 1 | Conductors deadended in vertical configuration on poles | 54.4–C4 |
| | 2 | Conductors deadended in horizontal configuration | 54.4–D8 |
| (ee) | Clearance requirements for certain voltage classifications | | 54.4–D2 |
| (ff) | Not applicable to communication conductors | | 84.4–D |
| (gg) | Clearance from crossarms may be reduced for certain conductors | | |
| | 1 | Suitable insulated leads to protect runs | 54.4–E |
| | 2 | Leads of 0 - 5,000 volts to equipment | 54.4–E |
| | 3 | Leads of 0 - 5,000 volts to cutouts or switches | 58.3–A2 |
| (hh) | Reduced clearance permitted from temporary fixtures and lighting circuits 0 - 300 volts | | 78.3–A1 |
| (ii) | Special Clearances Required Above Public and Private Swimming Pools | | |
| | 1 | Supply line conductors | 54.4–A3 |
| | 2 | Supply service drops | 54.8–B5 |
| | 3 | Communication line conductors | 84.4–A5 |
| | 4 | Communication service drops | 84.8–C5 |
| | 5 | Supply guys, span wires | 56.4–A3 |
| | 6 | Communication guys | 86.4–A3 |
| (jj) | May be decreased in partial underground distribution | | 54.4–D2 |

**References to Rules Modifying Minimum Clearances in Table 1** Rule

(kk) Shall be increased by 0.025 feet per kV in excess of 300 kV

(ll) Shall be increased by 0.04 feet per KV in excess of 300 kV

(mm) Proposed clearances to be submitted to the cpuc prior to construction for circuits in excess of 550 kV.

(nn) Voltage shown in the table shall mean line–to–ground voltage for direct current (DC) systems

(oo) May Be reduced for grounded or multi–conductor cables

1 Grounded cables 57.4–H

2 Multi–Conductor cables 54.10–B2

(pp) May be reduced to 4 feet for voltages below 7,500 volts 54.4–D3

(qq) May be reduced to 6 feet for voltages below 75 kV

(rr) May be reduced for supply service drops 54.8–D1

(ss) May be reduced for communications service drops 84.8–E1

(tt) Where a federal agency or surrogate thereof has issued a crossing permit, clearances of that permit shall govern.

(uu) Or where sailboating is prohibited and where other boating activities are allowed

(vv) Clearance above contiguous ground shall be 5 feet greater than in cases 11 or 12 for the type of water area served for boat launch facilities and for area contiguous thereto, that are posted, designated or specifically prepared for rigging of sailboats or other watercraft.

(ww) For controlled impoundments, the surface areas and corresponding clearances shall be based upon the high water level. for other waters, the surface area shall be that enclosed by its annual flood level. the clearance over rivers, streams and canals shall be based upon the largest surface areas of any one–mile long segment which includes the crossing. The clearance over a canal, river or stream normally used to provide access for sailboats to a larger body of water shall be the same as that required for the larger body of water.

(xx) Water areas are lakes, ponds, reservoirs, tidal waters, rivers, streams and canals without surface obstructions.

(yy) May be reduced over non–walkable structures 54.8 (Table 10)

(zz) May be reduced to 2 feet for conductors insulated in accordance with 20.9–G

(aaa) Special requirements for communication and supply circuits energized at 0 - 750 volts 35

(bbb) May be reduced for conductor of less than 60,000 volts when protected from abrasion and grounding by contact with tree 35

Rule

(ccc) For 22.5 kV to 105 kV, minimum clearance shall be 18 inches.

(ddd) Clearances in this case shall be maintained for normal annual weather variations, rather than at 60 degrees, no wind.

(eee) May be reduced to 18 feet if the voltage does not exceed 1000 volts and the clearance is not reduced to more than 5% below the reduced value of 18 feet because of temperature and loading as specified in Rules 37 and 43.

(fff) Clearances in this case shall be increased for conductors operating above 72 kV, to the following:

1 Conductors operating between 72kV and a 110 kV shall maintain a 72 inch clearance

2 Conductors operating above 110 kV shall maintain a 120 inch clearance

(ggg) Shall be increased by 0.40 inch per kV in excess of 500 kV

(hhh) The High Fire-Threat District is defined in GO 95, Rule 21.2-D.

(iii) May be reduced to 18 inches for conductors operating less than 2.4 kV.

(jjj) Clearances in this case shall not apply to orchards of fruit, nut or citrus trees that are plowed or cultivated. In those areas Case 13 clearances shall apply.

(kkk) For communication conductors across or along public thoroughfares see 84.4–A(6).

Note: Revised February 1, 1948 by Supplement No. 1 (Decision No. 41134, Case No. 4324); January 2, 1962 by Resolution E–1109; February 7, 1964 by Decision No. 66707; March 29, 1966 by Decision No. 70489; August 9, 1966 by Decision No. 71094; September 18, 1967 by Decision No. 72984; March 30, 1968 by Decision No. 73813; January 8, 1980 by Decision No. 91186; March 9, 1988 by Resolution E–3076; November 21, 1990 by Resolution SU–6; January 21, 1992 by Resolution SU–10; and November 6, 1992 by Resolution SU–15, September 20, 1996 by Decision 96–09–097, October 9, 1996 by Resolution SU–40, January 23, 1997 by Decision 97–01–044, January 13, 2005 by Decision No. 0501030 , January 12, 2012 by Decision No. 1201032, January 21, 2015 by Decision 1501005, and December 14, 2017, by Decision D. 17-12-024.

# Appendix E
# Clearance of Poles, Towers and Structures from Railroad Tracks

Where poles, towers or other line structures are set in proximity to railroad tracks, the minimum side clearance from the face of a pole, tower or structure to the center line of the tangent railroad track shall be 8 feet 6 inches.

This side clearance may be decreased or shall be increased in accordance with this Commission's General Order 26–D, Sections 3.7, 3.16, 3.20, 8.1, 9.2, 9.3 and 9.4. For tracks used exclusively for Light–rail Transit operations, the side clearances may be further decreased in accordance with this Commission's General Order 143A, Section 9.06.

Clearance requirements above railroads are shown in General Order No. 95, in Rules 37, Table 1, 54.4–B, 56.4–B, 57.4–B, 58.5–B2, 74.4–B, 77.4–A, 84.4–B. 86.4–B, 87.4–B and 113.5.

Note: Revised January 19, 1994 by Resolution SU–25.

The following are guidelines to Rule 35.

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances than those listed below to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, fire risk, and vegetation trimming requirements that are applicable to State Responsibility Area lands pursuant to Public Resource Code Sections 4102 and 4293.

| **Voltage of Lines** | **Case 13 of Table 1** | **Case 14 of Table 1** |
|---|---|---|
| Radial clearances for any conductor of a line operating at 2,400 or more volts, but less than 72,000 volts | 4 feet | 12 feet |
| Radial clearances for any conductor of a line operating at 72,000 or more volts, but less than 110,000 volts | 6 feet | 20 feet |
| Radial clearances for any conductor of a line operating at 110,000 or more volts, but less than 300,000 volts | 10 feet | 30 feet |
| Radial clearances for any conductor of a line operating at 300,000 or more volts | 15 feet | 30 feet |

Note: Added November 6, 1992 by Resolution SU–15. Revised September 20, 1996 by Decision No. 96–09–097, August 20, 2009 by Decision No. 09-08-029, January 12, 2012 by Decision No. 12-01-032, and December 14, 2017, by Decision D. 17-12-024.